To: DeLuca, Isabel[DeLuca.Isabel@epa.gov]
Cc: Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Lemon, Mollie[Lemon.Mollie@epa.gov]
From: Gunning, Paul
Sent: Fri 10/16/2015 11:42:21 PM
Subject: Re: PBS NEWSHOUR Methane interview request

Thanks Isabel

Paul M Gunning
202-251-1436

On Oct 16, 2015, at 6:10 PM, DeLuca, Isabel <DeLuca.Isabel@epa.gov> wrote:

Hi Paul,

Some background on this email I just cc'd you on, as an FYI… Just this afternoon Joe agreed to do an interview with PBS, on Monday at 10:15 , on EPA's oil and gas actions. This is a follow-on to PBS's coverage to the Four Corners Study (that article is at the bottom of the chain).

Ex. 5 - Deliberative Process

Thanks,
Isabel

From: DeLuca, Isabel
Sent: Friday, October 16, 2015 5:58 PM
To: McMichael, Nate; Goffman, Joseph
Cc: Millett, John; Davis, Alison; Drinkard, Andrea; Gunning, Paul
Subject: RE: PBS NEWSHOUR Methane interview request

Joe,

Here are some additional Q&As, based on some of the questions that the reporter had asked in her email. Please us know if you have questions.

Thanks,

Isabel

From: McMichael, Nate
Sent: Friday, October 16, 2015 3:59 PM
To: Goffman, Joseph
Cc: Millett, John; Davis, Alison; Drinkard, Andrea; DeLuca, Isabel
Subject: RE: PBS NEWSHOUR Methane interview request

Joe – Here are the materials that you asked for from the rollout, along with some info on the Four Corners study that Isabel passed along. I am also including her note on our emission estimates:

The original PBS article noted that the study's authors had suggested that EPA's methane estimates may be too low. In case that question comes up, here's our standard response

Ex. 5 - Deliberative Process

Please let me know if you need anything else.

Nate McMichael

US EPA Office of Air and Radiation

202-564-0382 (Office)

202-236-4176 (Cell)

From: Goffman, Joseph
Sent: Friday, October 16, 2015 2:31 PM
To: McMichael, Nate
Cc: Millett, John; Davis, Alison; Drinkard, Andrea; DeLuca, Isabel
Subject: RE: PBS NEWSHOUR Methane interview request

Sure thing. Thanks.

From: McMichael, Nate
Sent: Friday, October 16, 2015 2:30 PM
To: Goffman, Joseph
Cc: Millett, John; Davis, Alison; Drinkard, Andrea; DeLuca, Isabel
Subject: FW: PBS NEWSHOUR Methane interview request

Hi Joe – Would you be interested in doing this backgrounder with PBS Newshour? If so, it looks like there are a few open time slots on your calendar Monday morning.

Nate McMichael

US EPA Office of Air and Radiation

202-564-0382 (Office)

202-236-4176 (Cell)

From: Allen, Laura
Sent: Friday, October 16, 2015 2:21 PM
To: Millett, John; McMichael, Nate
Subject: PBS NEWSHOUR Methane interview request

Hey- PBS Newshour producer is looking for a background interview on the recent methane oil and gas announcement. This will be on background (agency official) and I wanted to see if Joe G. could do it. Reporter is talking to industry and enviro groups, and wants to make sure she understands what EPA has proposed. I'm sending her background info from the announcement. She would like to do the call on Mon.

Let me know if Joe is interested and what time would be best. Thanks!

Here's more on the story:

I'm working on a story about methane gas emissions: the extent and what's being done about them. I was intrigued by the NASA/JPL photographs about a year ago showing a hot spot over the Four Corners area in NW New Mexico (they did a recent web story on this). See recent story on similar topic below. Our story is focused on the San Juan Basin in New Mexico. I intend to start filming there on Wednesday (Oct 21). The story will air this fall.

Her questions:

- What was the agency's motivation for doing this?
- What is the timeline for implementation
- What will the impact be on climate? (is oil and gas the most significant source of methane emissions?)
- Why hasn't the issue received much media coverage?

- I've also learned recently that some companies are using technology to detect and reduce these emissions. What kind of technology? Does the rule require that technology?

Monday, Oct 19.

Time: 15 minutes max

On the Phone

KATHLEEN McCLEERY

Producer, Writer and Media Consultant

Special Correspondent, PBS NewsHour

RECENT STORY:

(Pbs newshour web story)

Why is there a huge methane hotspot in the American Southwest?

BY LAURA SANTHANAM June 3, 2015 at 12:40 PM EDT

The Four Corners region of the southwest United States is a magnificent, otherworldly place, marked by red rock vistas, ancient cliff dwellings and sweeping blue sky. The names alone paint a picture of the landscape: The Painted Desert. The Petrified Forest. Monument Valley.

This image shows methane hotspot, highlighted in red, in the Four Corners area. This map shows how much methane emissions varied from average background concentrations from 2003-2009 (dark colors are lower than average; lighter colors are higher. (AP Photo/NASA, JPL-Caltech, University of Michigan)

But billowing above the rust-colored earth is the country's largest concentration of methane, according to satellite data. That's because this spot where Utah, Colorado, Arizona and New Mexico meet is also home to one of the nation's most productive natural gas fields and coalbed methane basins. About 10 percent of the country's estimated methane emissions from natural gas is found in this region, according to recent scientific research and the Environmental Protection Agency.

Methane is odorless, colorless and invisible to the naked eye. Following carbon dioxide, methane ranks as the second most prevalent greenhouse gas emitted by human activity in the United States. But in the short term, atmospheric methane is more than 100 times more potent than carbon dioxide at holding the sun's heat, according to Colm Sweeney, the lead scientist for the NOAA Earth System Research Lab Aircraft Program.

"It's a very strong greenhouse gas and traps heat really effectively," he said. "It's like putting an inch of insulation in your attic versus putting 100 inches of insulation in your attic with the same amount of CO2."

Scientists first realized methane was flooding the Four Corners after a satellite in 2003 detected higher-than normal amounts of the gas. A year earlier, the European Space Agency had launched Envisat, an eight-ton, sun-powered satellite the size of a school bus. While orbiting the planet, its mission was to track ocean temperature and ozone depletion, improving environmental studies.

Onboard was SCIAMACHY, an image spectrometer that monitored gases in the Earth's atmosphere, including methane, and created novel data maps. For years, the satellite captured images of sunlight reflecting off the Earth's surface. Absorptions of methane in the data revealed its distribution around the globe.

But one day in April 2012, for reasons still unclear, ESA ground control crews lost all contact with Envisat and its instruments.

The satellite had disappeared, but the data remained.

A startling red spot of methane hovered over the U.S. Southwest, burning brighter than any other hotspot in the United States.

In that data, Christian Frankenberg, a scientist with NASA's Jet Propulsion Laboratory, found what he initially thought might be an error. A startling red spot of methane hovered over the U.S. Southwest, burning brighter, he said, than any other hotspot in the United States.

Atmospheric scientist Eric Kort of the University of Michigan plumbed the data further, using satellite images produced between 2003 and 2009. The team collected air samples, conducted on-the-ground observations, performed simulations and analyzed readings before concluding that the methane floating above the Four Corners represented the country's largest concentration of the gas. In findings they published in October in the journal Geophysical Research Letters, the scientists also suggested that the EPA was underestimating methane emissions nationwide, including in the Four Corners.

Still, they puzzled over the source of the hotspot.

HOW METHANE KILLED THE CANARY IN THE COAL MINE

The Four Corners is part of the San Juan Basin, a region that covers 7,500 square miles and is "the most productive coalbed methane basin in North America," according to the EPA. For years, oil and gas companies have tapped into this massive energy stash in the middle of the desert. About 60,000 wells are scattered across the area.

But scientists don't understand how such massive amounts of methane are getting released into the air. Is it coming from natural sources, like the exposed coal seam jutting above the earth's surface in parts of the San Juan Basin? Is it coming from open mine shafts or leaking equipment that belongs oil and gas companies? Is it a combination of these factors, or none of these factors?

"The interesting part of the Four Corners is that there's a lot of stuff coming out of these coal beds. I'm not going to say natural because we're not sure how much that is going into production is influencing how much seepage is coming up," Sweeney said.

Methane is generally harmless, but it can be problematic when it exists in extremely dense quantities or confined areas. Under sustained conditions for a long period of time, studies have found that people may have trouble breathing or even lose consciousness.

In cramped spaces like a coal mine, methane is dangerous and can ignite easily. That's where the term "canary in a coal mine" came from. If a caged canary in a mineshaft stopped singing and died, that signaled that there was too little oxygen and too much methane, carbon monoxide and other gases, and miners needed to get out, stat.

That's also why coal mines typically pump fresh air into the shaft and use ventilation systems to dilute the gas.

Often when industrial sources emit methane, they also release volatile organic compounds into the air, said Mary Uhl, an environmental protection specialist with the federal Bureau of Land Management. These compounds trigger chemical reactions thatcreate ozone, which can harm people with asthma or respiratory conditions. Ozone levels in the Four Corners hover at 0.071 parts per million, which means they just barely meet the Environmental Protection Agency's national air quality standards of 0.075 parts per million. And if federal standards drop to 0.065 to 0.070 parts per million, as proposed, the Four Corners would no longer meet the legal rate.

That's a problem normally seen in urban areas with far more people and cars than what you would find in the Four Corners, Uhl said. "Rural areas of the country haven't typically bumped up against the federal air quality standard for ozone," she said.

A reduction in methane emissions would likely reduce volatile organic compounds along with ozone levels, Uhl said.

U.S. RegionsOzone Levels (PPM)Ozone levels in U.S. cities and the Four Corners region

Data from U.S. Environmental Protection Agency, Graphic by Megan Hickey

In April, a team of scientists traveled to the Four Corners to study methane in this region. They flew five aircraft with equipment designed to detect the gas and drove two research vehicles roughly 3,000 miles — the distance between Los Angeles and Portland, Maine. Ultimately, they collected hundreds of air samples of methane that will be analyzed for 55 different trace gases and two methane isotopes.

Now the scientists are sifting through terabytes of data, searching for answers. Air samples must be analyzed, and maps studied further to identify the origins of the gas.

"This is where the detective work comes in, and where the fun of it comes in," Sweeney with NOAA said.

It will take months, but Frankenberg said he hopes that the team can produce findings by the end of the year.

"It's really rare that we get to observe an anomaly like this, but at the same time have measurements on the ground that confirm it," he said.

THE HEALTH FALLOUT

Meanwhile, people who live in the Four Corners have mobilized to address the issue. Residents in the region have long reported respiratory problems. High ozone days when ground-level ozone blankets parts of the region are not uncommon, and lead to frequent emergency room visits.

Community and government leaders have formed the Four Corners Air Quality Group, which meets periodically to figure out how to mitigate the effects of methane and the ozone that its presence aggravates.

San Juan County, which is in the affected area, got a C grade for ozone-related air quality, according to the American Lung Association's 2015 State of the Air report. But the link between ozone and respiratory problems extends beyond the Four Corners region. Studies have shown that visits to the emergency room for asthma are more frequent on high-ozone days, according to the EPA. Those with asthma may be more sensitive to ozone, this online report states, and "the injury, inflammation, and increased airway reactivity induced by ozone exposure may result in a worsening of a person's underlying asthma status, increasing the probability of an asthma exacerbation or a requirement for more treatment."

About 200 people attended a public forum in San Juan County's city of Farmington in April. Participants included members of the oil and gas industry, the local scientific community, nearby tribal communities and the general public.

Julia Madrid, 31, a baker in Durango, Colorado, was among them. She suffers from lupus and said she has wondered if the region's air has aggravated her illness. Her mother alerted her to a map of the region's methane hotspot in the local newspaper. Madrid's father mined coal, and her brother drilled for oil and gas.

<PBS 10.19.15 interview background.docx>

To: Weitz, Melissa[Weitz.Melissa@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; Franklin, Pamela[Franklin.Pamela@epa.gov]
From: Gunning, Paul
Sent: Thur 6/9/2016 6:13:40 PM
Subject: FW: AGA's Request for Extension of June 13 Methane Research Application Due Date until July 29 - FOA 0001538 Methane Emissions Mitigation and Quantification from Natural Gas Infrastructure
DOE Methane Emissions Mitigation and Quantification from Natural Gas Infrastructure_v2.docx

FYI

From: Lacey, Pam [mailto:PLacey@aga.org]
Sent: Thursday, June 09, 2016 1:50 PM
To: Jared.Ciferno@NETL.DOE.GOV
Cc: John.Hatfield@NETL.DOE.GOV; Dunham, Sarah <Dunham.Sarah@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>
Subject: AGA's Request for Extension of June 13 Methane Research Application Due Date until July 29 - FOA 0001538 Methane Emissions Mitigation and Quantification from Natural Gas Infrastructure
Importance: High

Dear Director Ciferno:

I am writing to express concern about the very short turnaround for developing proposals and assembling the required cost share funding for methane research under the referenced FOA. This is an important area of research that should help develop more accurate, updated emission data for EPA's use in the annual GHG Inventory.

A sufficient number of gas utilities have stepped up to support the only proposal I know of regarding the distribution component (plastic pipe and industrial meters), but research teams need more time to pull together the necessary detailed proposals to garner sufficient cost-share support for the underground storage and gathering line topics. I know of only three proposals under development in response to this FOA, and it appears that only one (for natural gas distribution topics) is likely to be ready for submission by the current June 13th deadline. The only proposal for underground storage apparently will definitely not go forward if you maintain the current June 13th deadline. If you extend the deadline into July, you would likely receive a more complete response to your FOA, and that would better serve your purpose of supporting EPA's methane emissions data and mitigation efforts. Even with this extension, you will

probably only receive three proposals, so it should still be feasible to review that small number of proposals and make a decision in time to award grants by the end of September 2016.

AGA hereby respectfully requests that NETL extend the Monday June 13, 2016 deadline for the attached FOA 00001538 and set a new deadline for the submission of responsive proposals by Friday July 29, 2016.

Respectfully,

Pamela A. Lacey | Chief Regulatory Counsel

American Gas Association

400 N. Capitol St., NW | Washington, DC | 20001

P: 202-824-7340 | M: 202-809-6565 | F: 202-824-9190 | placey@aga.org

The American Gas Association represents more than 200 local energy companies committed to the safe and reliable delivery of clean natural gas to nearly 69 million customers throughout the nation.

To: DeLuca, Isabel[DeLuca.Isabel@epa.gov]; Krieger, Jackie[Krieger.Jackie@epa.gov]
Cc: Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]
From: Gunning, Paul
Sent: Mon 12/11/2017 8:27:02 PM
Subject: FW: inquiry CPI

[redacted]

INTERNAL CPI draft 4.docx

This looks fine to me. Looping in Bill and Melissa too.

Paul

From: DeLuca, Isabel
Sent: Monday, December 11, 2017 3:14 PM
To: Gunning, Paul <Gunning.Paul@epa.gov>; Krieger, Jackie <Krieger.Jackie@epa.gov>
Subject: inquiry CPI

Hi Paul and Jackie,

We have had a series of questions from the Center for Public Integrity about emissions factors EPA uses for various purposes. These have focused on factors used for permitting and other OAQPS work, but in the last set of questions CPI also asked about emissions factors used for methane emissions from the oil and gas sector.

Attached are all the questions and draft responses for the latest set of questions. At the bottom of the set, there is a description of the Inventory and GHGRP, and links to where to find information on the emissions factors used. Cut-and-dry language, but I wanted to make you aware. (I expect we may have follow-on questions.) We're planning to send this out tomorrow morning, if possible.

Thanks!
Isabel

Isabel DeLuca

Office of Air and Radiation, US EPA

(202) 343-9247

To: Irving, Bill[Irving.Bill@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]
From: Gunning, Paul
Sent: Thur 5/26/2016 8:02:07 PM
Subject: RE: USGS EPA data request for calculating greenhouse gas emissions from Federal lands

Bill/Melissa – just wanted to follow up on this. I thought the ask "we are planning to brief DOI

Ex. 5 - Deliberative Process

From: Irving, Bill
Sent: Wednesday, May 18, 2016 1:50 PM
To: Gunning, Paul <Gunning.Paul@epa.gov>
Subject: Fwd: USGS EPA data request for calculating greenhouse gas emissions from Federal lands

Sent from my iPhone

Begin forwarded message:

From: Peter Warwick <pwarwick@usgs.gov>
Date: May 18, 2016 at 9:54:31 AM EDT
To: <irving.bill@epa.gov>, <hockstad.leif@epa.gov>, "Weitz, Melissa" <weitz.melissa@epa.gov>
Cc: Matthew Merrill <mmerrill@usgs.gov>, Philip Freeman <pfreeman@usgs.gov>, Robin O'Malley <romalley@usgs.gov>
Subject: USGS EPA data request for calculating greenhouse gas emissions from Federal lands

All,

This is an update on USGS activities on calculating greenhouse gas emissions related to fossil fuel production from Federal lands and a request for assistance and information from

Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

We are planning to brief DOI Deputy Secretary Conner on June 9, and in preparation, we ask that you provide us with a time and cost estimate for the above items by May 27, 2016.

Thanks so much, and let us know if you have any questions.

Regards,

Peter

++++++++++++++++++

Peter D. Warwick

U.S. Geological Survey

956 National Center

12201 Sunrise Valley Drive

Reston, VA 20192

Tel: 1-703-648-6469

Fax: 1-703-648-6419

Email: pwarwick@usgs.gov

http://energy.usgs.gov

http://go.usa.gov/8X8

++++++++++++++++++

To: Fawcett, Allen[Fawcett.Allen@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Alsalam, Jameel[Alsalam.Jameel@epa.gov]; DeLuca, Isabel[DeLuca.Isabel@epa.gov]; Gordon, Jessica M[Gordon.Jessica@epa.gov]
Cc: Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]
From: Gunning, Paul
Sent: Mon 6/27/2016 4:50:31 PM
Subject: FW: NALS Methane Q and A

Ex. 5 - Deliberative Process

Melissa – can you please work with Isabel to suggest a response.

Thanks

Paul

From: Vahlsing, Candace M. EOP/WHO [Ex. 6 - Personal Privacy]
Sent: Monday, June 27, 2016 12:24 PM
To: Gordon, Jessica M <Gordon.Jessica@epa.gov>; Goffman, Joseph <Goffman.Joseph@epa.gov>; McCabe, Janet <McCabe.Janet@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>
Cc: Utech, Dan G. EOP/WHO <[Ex. 6 - Personal Privacy]Duke, Rick D. EOP/CEQ [Ex. 6 - Personal Privacy]
Subject: NALS Methane Q and A

Hi Team,

Thank you so much for your help securing the methane target with Mexico. Your team was integral to our success.

We're finalizing the NALS Q and A. On the methane questions, if we are pressed on how many reductions the entire goal would achieve we'd like to provide an estimate.

This is what we are thinking, there are two options. Do you have a preference?

Ex. 5 - Deliberative Process

We'll need to reach to Canada and Mexico this evening to get signoff on the numbers so any input you can provide this afternoon would be helpful.

Happy to answer any questions.

Thank you very much

To: Davis, Alison[Davis.Alison@epa.gov]; Dennis, Allison[Dennis.Allison@epa.gov]; Jones, Enesta[Jones.Enesta@epa.gov]
Cc: Nayem, Tasfia[Nayem.Tasfia@epa.gov]; McMichael, Nate[McMichael.Nate@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Cozzie, David[Cozzie.David@epa.gov]; Moore, Bruce[Moore.Bruce@epa.gov]
From: Gunning, Paul
Sent: Fri 8/14/2015 1:04:05 PM
Subject: RE: ACTION: NYT RE: EDF methane study

Thanks Alison. They are actually giving us (Joe G.) a briefing on this later today. Melissa (copied above) was actually one of the peer reviewers for the study.

From: Davis, Alison
Sent: Friday, August 14, 2015 9:00 AM
To: Dennis, Allison; Jones, Enesta
Cc: Nayem, Tasfia; McMichael, Nate; Gunning, Paul; Waltzer, Suzanne
Subject: RE: ACTION: NYT RE: EDF methane study

If you get a copy, let us know!

From: Dennis, Allison
Sent: Friday, August 14, 2015 8:59 AM
To: Jones, Enesta <Jones.Enesta@epa.gov>
Cc: Nayem, Tasfia <Nayem.Tasfia@epa.gov>; McMichael, Nate <McMichael.Nate@epa.gov>; Davis, Alison <Davis.Alison@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; Waltzer, Suzanne <Waltzer.Suzanne@epa.gov>
Subject: Re: ACTION: NYT RE: EDF methane study

Plus others in ccd
Sent from my iPhone

On Aug 14, 2015, at 8:35 AM, Jones, Enesta <Jones.Enesta@epa.gov> wrote:

Reflagging. And + Alison and Nate since its methane.

Enesta Jones

U.S. EPA, Office of Media Relations

Desk: 202.564.7873

Cell: 202.236.2426

On Aug 13, 2015, at 5:58 PM, Jones, Enesta <Jones.Enesta@epa.gov> wrote:

He is looking for comment on the study by COB tomorrow.

Enesta Jones

U.S. EPA, Office of Media Relations

Desk: 202.564.7873

Cell: 202.236.2426

Begin forwarded message:

From: "Schwartz, John" <jswatz@nytimes.com>
Date: August 13, 2015 at 5:39:13 PM EDT
To: "Jones, Enesta" <Jones.Enesta@epa.gov>
Subject: Re: NY Times reporter has a question about methane

Oh! Sorry. I'll be finishing up the writing on Monday, though I'd love to have the conversation (or get the statement) by end of business tomorrow.

On Thu, Aug 13, 2015 at 5:37 PM, Jones, Enesta <Jones.Enesta@epa.gov> wrote:

Deadline, John?

From: Schwartz, John [mailto:jswatz@nytimes.com]
Sent: Thursday, August 13, 2015 5:36 PM
To: Jones, Enesta
Subject: NY Times reporter has a question about methane

Dear Ms. Jones,

Thanks again for your help a couple of weeks ago on the methane measurement story. I'm back with another methane story -- this time concerning EDF's 16th methane study, which will be out next Tuesday and has implications for the EPA greenhouse gas inventory. Who would I talk with about this study, which is still under embargo? (I'd be happy to send it if whoever I deal with honors the embargo.)

best wishes,

John

--

John Schwartz

The New York Times

jswatz@nytimes.com / twitter.com/jswatz

Telephone: 212 556 7353

620 Eighth Avenue, New York, NY 10018

Speaking only for myself since 1957

--

John Schwartz

The New York Times

jswatz@nytimes.com / twitter.com/jswatz

Telephone: 212 556 7353

620 Eighth Avenue, New York, NY 10018

Speaking only for myself since 1957

To: Alsalam, Jameel[Alsalam.Jameel@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Cozzie, David[Cozzie.David@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; Hambrick, Amy[Hambrick.Amy@epa.gov]; Macpherson, Alex[Macpherson.Alex@epa.gov]; Fawcett, Allen[Fawcett.Allen@epa.gov]; Davis, Alison[Davis.Alison@epa.gov]; Franklin, Pamela[Franklin.Pamela@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]
Cc: Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]; Krieger, Jackie[Krieger.Jackie@epa.gov]
From: Gunning, Paul
Sent: Thur 5/26/2016 2:32:34 PM
Subject: FW: progress towards methane goal
Supplementary Material - ONG projections_052616v1.docx
ONG projections summary_5-25-16_v3.docx

Just wanted to make sure everyone has the latest. I incorporated Joe's changes in the attached……..

From: Goffman, Joseph
Sent: Thursday, May 26, 2016 10:16 AM
To: Gunning, Paul <Gunning.Paul@epa.gov>
Cc: Dunham, Sarah <Dunham.Sarah@epa.gov>; Tsirigotis, Peter <Tsirigotis.Peter@epa.gov>
Subject: Re: progress towards methane goal

These look good to me. **Ex. 5 - Deliberative Process**

Ex. 5 - Deliberative Process

Sent from my iPhone

On May 26, 2016, at 3:23 PM, Gunning, Paul <Gunning.Paul@epa.gov> wrote:

Joe

I hope your vacation is going well. Attached you will find the updated table that estimates progress toward the 40-45% goal. It includes emissions projections based on the latest GHG inventory, as well as reduction estimates for individual policies based on the respective regulatory documents.

There is also a one-page, supplementary document that provides additional background and discusses some of our assumptions and methods. This document was more for you and our internal consumption, of course it is up to you if you want to share it

Please let me know if you have any questions or need anything else.

Paul

From: Goffman, Joseph
Sent: Tuesday, May 24, 2016 1:55 PM
To: Gunning, Paul <Gunning.Paul@epa.gov>
Cc: Dunham, Sarah <Dunham.Sarah@epa.gov>; Tsirigotis, Peter <Tsirigotis.Peter@epa.gov>
Subject: Re: progress towards methane goal

Thanks, Paul. I will be on my iPhone and should be able to look at the table and give you feedback. Meanwhile, I will let Dan know what the schedule is. Thanks, again.

Sent from my iPhone

On May 24, 2016, at 1:05 PM, Gunning, Paul <Gunning.Paul@epa.gov> wrote:

> Joe – we are developing a draft table that updates the emissions reductions estimates based on changes made in the final rule, etc. Folks are working on it now and plan to have a draft to Peter and I by tomorrow. Depending on how it looks, we could get you something to look at by COB tomorrow or first thing Thursday. We would be in position to get Dan something by Thursday, Friday at the latest.
>
> Paul
>
> **From:** Goffman, Joseph
> **Sent:** Tuesday, May 24, 2016 11:36 AM
> **To:** Gunning, Paul <Gunning.Paul@epa.gov>
> **Cc:** Dunham, Sarah <Dunham.Sarah@epa.gov>
> **Subject:** Fwd: progress towards methane goal

Any sense of when you will know what this will take? Not intending to rush you, but it would be good to do this right and to let Dan know sooner rather than later what this might take and what a reasonable expectation is. Thanks.

Sent from my iPhone

Begin forwarded message:

From: "Goffman, Joseph" <Goffman.Joseph@epa.gov>
Date: May 23, 2016 at 4:55:17 PM EDT
To: "Utech, Dan G. G. EOP/WHO" <Dan_G._Utech@who.eop.gov>
Subject: Re: progress towards methane goal

Won't know until tomorrow AM what a doable time frame is. Will let you know. Thanks

Sent from my iPhone

On May 23, 2016, at 2:49 PM, Goffman, Joseph <Goffman.Joseph@epa.gov> wrote:

Got it. Will let you know if that is not doable. Thanks.

Sent from my iPhone

On May 23, 2016, at 2:17 PM, Utech, Dan G. G. EOP/WHO

Ex. 6 - Personal Privacy

wrote:

Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process Possible to produce by midweek? Thanks.

<Supplementary Material - ONG projections_052616v1.docx>

<ONG projections summary_5-25-16_v3.docx>

To: Weitz, Melissa[Weitz.Melissa@epa.gov]
From: McKittrick, Alexis MW (UNC)
Sent: Mon 4/11/2016 8:18:50 PM
Subject: slides for tomorrow
EOP Methane Monitoring April 4 2016 interagency meeting handouts.pdf

Melissa,

Attached are the draft slides for tomorrow with the concept papers attached at the end.

See you tomorrow,

Alexis

Alexis McKittrick, Ph.D.

Research Staff Member

Institute for Defense Analyses

Science and Technology Policy Institute

1899 Pennsylvania Ave. NW, Suite 520

Washington, DC 20006

(202) 419-5412

amckittr@ida.org

To: Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; Franklin, Pamela[Franklin.Pamela@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Banks, Julius[Banks.Julius@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]
Cc: Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]
From: Gunning, Paul
Sent: Thur 1/14/2016 1:22:07 PM
Subject: FW: EPA SOTU Fact Sheet Master edits 1 12 at 4 58PM (002)_bf.docx
EPA SOTU Fact Sheet Master edits 1 12 at 4 58PM (002)_bf.docx
ATT00001.htm

Not sure who is in and can take a quick look. The text looks fine, can someone please check the methane oil and gas #s

thanks

From: Goffman, Joseph
Sent: Wednesday, January 13, 2016 11:14 PM
To: Dunham, Sarah <Dunham.Sarah@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; Krieger, Jackie <Krieger.Jackie@epa.gov>; Newberg, Cindy <Newberg.Cindy@epa.gov>
Cc: Millett, John <Millett.John@epa.gov>; Drinkard, Andrea <Drinkard.Andrea@epa.gov>
Subject: Fwd: EPA SOTU Fact Sheet Master edits 1 12 at 4 58PM (002)_bf.docx

Please take a look at the methane and HFC bullets as early in the AM as possible. Thanks.

- Joseph Goffman

Sent from my iPhone

Begin forwarded message:

From: "Harrison, Melissa" <Harrison.Melissa@epa.gov>
Date: January 13, 2016 at 10:03:34 PM EST
To: "McCabe, Janet" <McCabe.Janet@epa.gov>, "Goffman, Joseph" <Goffman.Joseph@epa.gov>
Cc: "Purchia, Liz" <Purchia.Liz@epa.gov>, "Drinkard, Andrea" <Drinkard.Andrea@epa.gov>, "Millett, John" <Millett.John@epa.gov>, "Fried, Becky" <Fried.Becky@epa.gov>
Subject: Fwd: EPA SOTU Fact Sheet Master edits 1 12 at 4 58PM (002)_bf.docx

Good evening,

I apologize for the late email, but we have just received our edited SOTU factsheet back from the WH. Becky has taken a stab at it and we would like to have you take one last look. If possible, we would like to have edits back tomorrow morning since the WH wants to release tomorrow (distribution plans still unknown).

Thanks again for all your help and understanding. I will be in the road tomorrow so please reply all so Liz and Becky can finalize and share with the WH.

Cheers,

Melissa

Melissa J. Harrison

Press Secretary

U.S. Environmental Protection Agency

Office: (202) 564-8421

Mobile: (202) 697-0208

Harrison.Melissa@epa.gov

Begin forwarded message:

From: "Fried, Becky" <Fried.Becky@epa.gov>
Date: January 13, 2016 at 9:14:58 PM EST
To: "Harrison, Melissa" <Harrison.Melissa@epa.gov>, "Purchia, Liz" <Purchia.Liz@epa.gov>
Subject: EPA SOTU Fact Sheet Master edits 1 12 at 4 58PM (002)_bf.docx

Attached includes a few responses to comments. My take is that the attached ("accepting all") is fine. Thx!

To: Tang, Natalie[Tang.Natalie@epa.gov]
Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]
From: McKittrick, Alexis
Sent: Wed 3/9/2016 9:21:39 PM
Subject: FW: NSPS RTC on pneumatic and compressor emissions
RTC compressor and controllers 3 6 AM mw.docx

Hi Natalie,

Melissa and I have been iterating on some preamble language on compressors and pneumatic controllers for the final NSPS OOOOa rule (attachment is internal and deliberative). I hope you don't mind, but I volunteered you to check the onshore production centrifugal compressor numbers in the response to the first question.

Do you think you could check this afternoon or tomorrow first thing? We need to get our draft preamble text to the OAQPS folks by Noon tomorrow.

Thanks!

Alexis

From: Weitz, Melissa
Sent: Wednesday, March 09, 2016 4:16 PM
To: McKittrick, Alexis <McKittrick.Alexis@epa.gov>
Subject: RE: NSPS RTC on pneumatic and compressor emissions

Thanks!

I accepted your changes and left bubbles where I didn't or had questions. It would be great if Natalie could do a quick check on the well site centrifugal numbers.

Melissa

From: McKittrick, Alexis
Sent: Wednesday, March 09, 2016 2:41 PM

To: Weitz, Melissa <Weitz.Melissa@epa.gov>
Subject: RE: NSPS RTC on pneumatic and compressor emissions

Melissa,

Attached are my suggested edits and comments on the NSPS pneumatics / compressor responses. Feel free to give me a call to discuss.

Let me know if you need anything else from me to get these into the preamble / RTC.

Regards,

Alexis

To: Irving, Bill[Irving.Bill@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]
From: Gunning, Paul
Sent: Fri 1/8/2016 1:17:20 PM
Subject: FW: your departure from OAR

An excerpt from Terry's long email below…..Is this worth advocating for?

Ex. 5 - Deliberative Process

From: McCabe, Janet
Sent: Thursday, January 07, 2016 7:58 PM
To: Page, Steve <Page.Steve@epa.gov>; Koerber, Mike <Koerber.Mike@epa.gov>; Dunham, Sarah <Dunham.Sarah@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; Jordan, Deborah <Jordan.Deborah@epa.gov>; Goffman, Joseph <Goffman.Joseph@epa.gov>
Subject: FW: your departure from OAR

Sounds like the meeting with NASA went well. Couple of questions for you guys—

Ex. 5 - Deliberative Process

Thanks.

From: Keating, Terry
Sent: Thursday, January 07, 2016 12:57 PM
To: McCabe, Janet <McCabe.Janet@epa.gov>
Subject: RE: your departure from OAR

Dear Janet,

Thanks for your note on Monday. You might see me around for a little while longer as my transfer has been hung up waiting to make it through the log jam for background checks. I'm hoping that my position in ORD will enable me to continue to work on many of the same issues and interests I've pursued over the last 17 years in OAR, and maybe be more effective, at least on some issues! But OAR will never be far from my mind. (You can take the person out of Air, but you can't take the Air out of … or something like that!)

Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

As always, I hope you find this information useful.

Terry

Terry J. Keating, Ph.D.

U.S. Environmental Protection Agency (OAR/OAPPS)

1200 Pennsylvania Ave NW (MC 6103A), Washington DC 20460

Phone: +1-202-564-1174 Fax: +1-202-564-1554 Mobile: +1-202-834-8454

From: McCabe, Janet
Sent: Monday, January 04, 2016 12:44 PM
To: Keating, Terry <Keating.Terry@epa.gov>
Subject: your departure from OAR

Terry—I was very sorry I had to miss your going away from OAR event before the holidays. I

can't remember if it was Paris or some other conflict, but I would have certainly stopped by if I could have.

You have been a big part of OAR over the years—more than I even know—and contributed significantly to the work on ozone, toxics and other issues. I will miss seeing you around the WJCN 5400s, but I am very glad to think of you ensconced in ORD, carrying the OAR ethic and vibe with you.

--Janet

To: Franklin, Pamela[Franklin.Pamela@epa.gov]; Banks, Julius[Banks.Julius@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]
Cc: Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]
From: Gunning, Paul
Sent: Wed 3/2/2016 4:27:01 PM
Subject: FW: OG 2-pager
OG new info 2 29 16_v2.docx

FYI…….an updated version of what I sent along on Monday.

From: Tsirigotis, Peter
Sent: Tuesday, March 01, 2016 9:52 AM
To: Gunning, Paul <Gunning.Paul@epa.gov>
Subject: OG 2-pager

The latest file

To: Tom Moore[tmoore@westar.org]
Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]
From: McKittrick, Alexis
Sent: Thur 6/18/2015 3:37:40 PM
Subject: RE: encouraging Operators to use 2014 "Deferred Data" reports to complete WRAP O&G Emission Inventory surveys in selected Western Basins

Tom,

I just sent you a meeting invitation for 3:30 PM eastern. Please forward it on to the others you would like to include in the call.

Alexis

From: Tom Moore [mailto:tmoore@westar.org]
Sent: Thursday, June 18, 2015 10:48 AM
To: McKittrick, Alexis
Cc: Weitz, Melissa
Subject: RE: encouraging Operators to use 2014 "Deferred Data" reports to complete WRAP O&G Emission Inventory surveys in selected Western Basins
Importance: High

Sorry, let's please amend the call time to 330 PM EDT / 130 PM MDT. I think we need a max of 30 mins. Thanks again.

Tom Moore, WRAP Air Quality Program Manager

Western States Air Resources Council (WESTAR) | e: tmoore@westar.org | o: 970.491.8837

Western Regional Air Partnership | www.wrapair2.org

From: Tom Moore
Sent: Thursday, June 18, 2015 8:47 AM
To: 'McKittrick, Alexis'

Cc: Weitz, Melissa
Subject: RE: encouraging Operators to use 2014 "Deferred Data" reports to complete WRAP O&G Emission Inventory surveys in selected Western Basins
Importance: High

Hello, Alexis and Melissa – thanks for finding time to talk. I am on the phone with OAQPS until at least 230 PM EDT, maybe until 3 EDT. So I can take a breath, could we talk at 4 PM EDT today? I would like to include Amnon Bar-Ilan and John Grant from ENVIRON who are in the Pacific time zone, so I can work on getting them available at that time. They are my leads on the surveys we are sending out soon. So a conference line in an appt. would be great. I can forward to them.

Thanks.

Tom Moore, WRAP Air Quality Program Manager

Western States Air Resources Council (WESTAR) | e: tmoore@westar.org | o: 970.491.8837

Western Regional Air Partnership | www.wrapair2.org

From: McKittrick, Alexis [mailto:McKittrick.Alexis@epa.gov]
Sent: Thursday, June 18, 2015 8:20 AM
To: Tom Moore
Cc: Weitz, Melissa
Subject: RE: encouraging Operators to use 2014 "Deferred Data" reports to complete WRAP O&G Emission Inventory surveys in selected Western Basins

Tom,

Thanks for your note and your voicemail from late yesterday. It looks like Melissa and I can be available for a call at 2:30PM eastern today. Does that work for you? If so, do you want us to just call your office number at that time? I can set up a conference call line, if you'd like to include others.

Regards,

Alexis

Alexis McKittrick, Ph.D.

Climate Change Division

U.S. Environmental Protection Agency

Phone: 202-343-9153

E-mail: mckittrick.alexis@epa.gov

From: Tom Moore [mailto:tmoore@westar.org]
Sent: Wednesday, June 17, 2015 3:58 PM
To: McKittrick, Alexis
Cc: Weitz, Melissa
Subject: encouraging Operators to use 2014 "Deferred Data" reports to complete WRAP O&G Emission Inventory surveys in selected Western Basins
Importance: High

Hello, Alexis and Melissa – I wondered if I could talk with you both, or at least Alexis on the Subpart W "Deferred Data" reporting by Operators for 2014. We have a couple or 3 survey-based O&G EIs in process for 2014 data, including all GHGs, and expect we will hear from the Operators that they had to report the Deferred Data by April 1, 2015. We'd like to modify our spreadsheet survey (example attached) so Operators can give us Subpart W data referenced to the "Sub-basins" we define.

Like to chat with you both if possible about this idea and help me prepare for the onslaught of "too much duplicate reporting" comments we expect and if this would be helpful to Subpart W data analysis and GHG EI efforts by EPA.

It would be great to talk this afternoon so you can think about my questions before answering. Thanks in advance.

Tom Moore, WRAP Air Quality Program Manager

Western States Air Resources Council (WESTAR) | e: tmoore@westar.org | o: 970.491.8837

Western Regional Air Partnership | www.wrapair2.org

From: Tom Moore
Sent: Tuesday, June 16, 2015 4:17 PM
To: Tom Moore
Subject: FW: Slides for tomorrow's National Oil and Gas Emissions Committee call

Tom Moore, WRAP Air Quality Program Manager

Western States Air Resources Council (WESTAR) | e: tmoore@westar.org | o: 970.491.8837

Western Regional Air Partnership | www.wrapair2.org

From: Gibbs, Mark [mailto:Mark.Gibbs@deq.ok.gov]
Sent: Wednesday, February 11, 2015 3:26 PM
To: 'airstar0077@gmail.com'; 'akcarter@adem.state.al.us'; 'amanda.l.davis@tn.gov'; 'ASadar@achd.net'; 'avickers@marama.org'; 'Beeler.Cindy@epa.gov'; 'brett.davis@wyo.gov'; 'brian.bohlmann@wyo.gov'; 'buzz.asselmeier@illinois.gov'; 'Byeong.Kim@dnr.state.ga.us'; Schroeder, Carrie; Garbe, William (Cooper); 'Cozzie.David@epa.gov'; 'curtis.taipale@state.co.us'; 'cwoods@csg.org'; 'dale.wells@state.co.us'; 'DALEBOUTR@michigan.gov'; 'darla.potter@wyo.gov'; 'Dewees.Jason@epa.gov'; Dan Johnson; 'ektrythall@nd.gov'; 'Erica.Fetty@epa.state.oh.us'; 'fcook@blm.gov'; 'Frantz.Chris@epa.gov'; 'gabrielle.petron@noaa.gov'; 'gary.reinbold@deq.idaho.gov'; 'Glover.Ed@epa.gov'; 'greg.lauderdale@tceq.texas.gov'; 'heather.sands@ncdenr.gov'; 'Holly.Ferguson@tceq.texas.gov'; 'hosford.chip@epa.gov'; 'Houyoux.Marc@epa.gov'; 'janssen@ladco.org'; 'Jim.Price@tceq.texas.gov'; 'JMCDILL@marama.org'; Kalfas, Joshua L.;

'jsemerad@nd.gov'; 'kaleri.cynthia@epa.gov'; 'karin.landsberg@alaska.gov'; 'Kathy.Pendleton@tceq.texas.gov'; 'kgee@pa.gov'; 'Koerber.Mike@epa.gov'; 'LDeahl@kdheks.gov'; 'lisa.ehrhart@deq.virginia.gov'; 'Lundelius.Diana@epa.gov'; 'Macpherson.Alex@epa.gov'; 'mark.jones@state.nm.us'; 'Mark.McMillan@dphe.state.co.us'; 'Mason.Rich@epa.gov'; 'masond1@michigan.gov'; 'McKittrick.Alexis@epa.gov'; 'michael.abraczinskas@ncdenr.gov'; 'Michael.Ege@tceq.texas.gov'; 'michael.trahiotis@ct.gov'; 'mike.pring@erg.com'; 'mike.schneider@state.nm.us'; 'Mindy.Hendrickson@wv.gov'; 'Moore.Bruce@epa.gov'; 'muhl@blm.gov'; 'nam.ed@epa.gov'; 'Nicholle.Worland@dep.state.nj.us'; 'oppapage@gw.dec.state.ny.us'; 'Page.Steve@epa.gov'; 'patricia_f_brewer@nps.gov'; 'pbarickman@utah.gov'; 'Rachel.Melton@tceq.texas.gov'; 'Ray.Papalski@dep.state.nj.us'; 'Regi.Oommen@erg.com'; 'riddick.lee@epa.gov'; 'Robert.J.Betterton@wv.gov'; 'rsmartin@nd.gov'; 'sarah.clouse@ecy.wa.gov'; 'sbogart@pa.gov'; 'Schell.Bob@epa.gov'; 'Shores.Richard@epa.gov'; 'Snyder.Jennifer@epa.gov'; 'sushma.masemore@ncdenr.gov'; 'szelinka@arb.ca.gov'; 'tcfoster@deq.virginia.gov'; 'Terry.Sara@epa.gov'; 'Thoma.Eben@epa.gov'; Tom Moore; 'tnguyen@arb.ca.gov'; Richardson, Thomas M.; 'tom.velalis@epa.state.oh.us'; 'Tonnesen.Gail@epa.gov'; Theresa Pella; 'Tsirigotis.Peter@epa.gov'; 'tune@adeq.state.ar.us'; 'twallace@mde.state.md.us'; 'Waltzer.Suzanne@epa.gov'; 'Wayland.Richard@epa.gov'; 'Weitz.Melissa@epa.gov'; 'wilbanmc@dhec.sc.gov'; 'Witosky.Matthew@epa.gov'; 'Wortman.Eric@epa.gov'; 'woswald@utah.gov'; 'young.carl@epa.gov'; 'Zubrow.Alexis@epa.gov'; 'Fry, Jessica'; 'Smith, James-D'; 'Wong.Richard@epa.gov'; 'stackhouse.debbie@epa.gov'; 'tammy.manning@ncdenr.gov'; 'james.r.smith@tn.gov'; 'paige.sprague@tceq.texas.gov'
Subject: Slides for tomorrow's National Oil and Gas Emissions Committee call

Slides for tomorrow's GHGRP presentation plus responses to the questions from the committee about the GHGRP and Flight are attached.

Will look forward to talking with you tomorrow at 2 pm Eastern.

Mark

From: Gibbs, Mark
Sent: Tuesday, February 10, 2015 9:38 AM
Subject: National Oil and Gas Emissions Committee - Thursday, February 12, 2015 Meeting Reminder

Hi All:

Attachments to this email:

- Minutes of January 2015 Meeting

- Compilation of Questions about GHGRP, e-GGRT, Flight, etc. (to be discussed in Agenda Item 2)

Meeting Time: **2:00 – 3:30 pm** Eastern, Thursday, February 12, 2015

Call-in number: Ex. 5 - Deliberative Process

Confirmation Number: Ex. 6 - Personal Privacy

1. Approve minutes of January meeting

2. GHGRP O&G data: Current Subpart W data elements – Alexis McKittrick (slides to follow)

3. Comment Period for Subpart W 2015 Revisions Proposals – now extended to Tuesday, February 24, 2015

Submit comments at http://www.regulations.gov/#!docketDetail;D=EPA-HQ-OAR-2014-0831

4. Public training webinar on using Facility Level Information on Greenhouse Gases Tool (FLIGHT), 3-4 pm, March 3, 2015

Register at https://attendee.gotowebinar.com/register/2267262588707184 65

5. Update on Public Review Draft of GHG National Inventory – Melissa Weitz

6. Colorado School of Mines Workshop on reconciliation of top-down and bottom-up methane emissions estimates, Denver Airport Marriott, February 24-25, 2015

7. Ways to improve speciation of O&G VOC emissions for AQ modeling – Alexis Zubrow

8. Recap of OAQPS call from January 28 on EPA's strategy on reducing methane and VOC's from the oil and natural gas industry

9. Reminder about O&G events at the 2015 International Emission Inventory Conference

10. Next meeting Thursday, March 12 at 2:00 pm – 3:30 pm Eastern, same call in number and confirmation number

Talk to you on Thursday,

Mark

Mark Gibbs

Emission Inventory Manager

Oklahoma DEQ

(405) 702-4179

To: Weitz, Melissa[Weitz.Melissa@epa.gov]
Cc: Irving, Bill[Irving.Bill@epa.gov]
From: Gunning, Paul
Sent: Tue 9/1/2015 5:58:39 PM
Subject: RE: summary of interagency call on Methane S&T Needs Activities

This is a great summary Melissa. Thanks for doing this!

Paul

From: Weitz, Melissa
Sent: Friday, August 28, 2015 4:53 PM
To: Gunning, Paul
Cc: Kocchi, Suzanne; Irving, Bill; DeFigueiredo, Mark; Hogan, Sean
Subject: summary of interagency call on Methane S&T Needs Activities

Yesterday (8/27), Mark and I called into the OSTP-led interagency call on methane activities. We gave an update on GHGRP and the GHG inventory, gave an overview of the proposed actions on oil and gas, and shared information on ORD activities. I've attached the activity write-ups submitted by participants prior to the call and slides presented by DOE and NOAA. Below is a brief overview of some of the highlights from each agency.

•□□□□□□□□ DOE walked through the NREL and NETL projects that we are already aware of, noted some of the QER recommendations, and gave an update on the status of the $10 million for improving the GHGI for natural gas systems (Senate EWD mark is $5 million, and House EWD mark is $0).

•□□□□□□□□ DOI discussed its proposed regs.

•□□□□□□□□ NASA noted its work using satellites and aircraft to measure methane.

•□□□□□□□□ NOAA highlighted its CH4 monitoring projects in the arctic region.

•□□□□□□□□ NSF work includes process studies related to both fossil and biological emissions.

•□□□□□□□□ USDA mentioned work with Tom Wirth to improve agricultural methane estimates in the GHGI, including improvements to the manure management and enteric estimates through modification of existing USDA survey instruments (e.g., farm census, ERS surveys) to obtain

specific data to improve our estimates, and improvements to estimates of non-CO2 emissions from burning, both grassland and crop residue.

•□□□□□□□□ PHMSA mentioned partnering with EPA in a number of areas, which we think is related to GasSTAR but we need to follow up with Carey to be sure.

There was no time for discussion after the interagency updates, but issues that the group expressed interest in during email exchanges prior to the call were 1) discussing and potentially coordinating on how we interact with NGOs, and 2) how what we do on unconventional oil and gas (both quantification and mitigation) might also apply internationally. It's unclear if OSTP will be convening another call soon (as far as I am aware, the most recent call prior to yesterday's was in October 2014), or if OSTP will be playing a more active role in coordinating.

Best,
Melissa

From: Brown, Austin Ex. 6 - Personal Privacy
Sent: Thursday, August 27, 2015 10:01 AM
To: Adrian.Down@Hq.Doe.Gov; Alexander.E.MacDonald@noaa.gov; Ann.Bartuska@osec.usda.gov; arlyn.andrews@noaa.gov; ateitz@blm.gov; bdeangelo@usgcrp.gov; bryan.willson@hq.doe.gov; camille.mittelholtz@dot.gov; charles.e.miller@jpl.nasa.gov; DeFigueiredo, Mark; douglas.morris@bsee.gov; Dunham, Sarah; ed.dlugokencky@noaa.gov; Elizabeth_Klein@ios.doi.gov; elke.hodson@hq.doe.gov; eric.smistad@hq.doe.gov; ESALTZMA@nsf.gov; gabrielle.petron@noaa.gov; garvin.heath@nrel.gov; Goffman, Joseph; Gullett, Brian; Gunning, Paul; hatch.mark@dol.gov; Irving, Bill; james.bradbury@hq.doe.gov; james.h.butler@noaa.gov; james.whetstone@nist.gov; jonathan.pershing@hq.doe.gov; Judith.Greenwald@Hq.Doe.Gov; kenneth.lee@dot.gov; Kenneth.w.jucks@nasa.gov; kfalkner@nsf.gov; Lori.Bruhwiler@noaa.gov; marlen.eve@ars.usda.gov; Marni.Lenahan@hq.doe.gov; Melanie.kenderdine@hq.doe.gov; Michaels.David@dol.gov; Miller, Andy; ncavallaro@nifa.usda.gov; nkornze@blm.gov; pshepson@nsf.gov; Rebecca.Shively@osec.usda.gov; riley.duren@jpl.nasa.gov; Robert.W.Smith@dot.gov; russell.c.schnell@noaa.gov; rwakimot@nsf.gov; sismith@nifa.usda.gov; Timothy.Skone@netl.doe.gov; Todd.Campbell@osec.usda.gov; Weitz, Melissa; whohenst@oce.usda.gov; mkuperberg@usgcrp.gov; amanda_leiter@ios.doi.gov; Paula.Gant@Hq.Doe.Gov; janice_schneider@ios.doi.gov; christopher.freitas@hq.doe.gov; rick.elliott@hq.doe.gov
Cc: Simon, Bob; Utech, Dan G.; Zaidi, Ali; Jencks, Fae; Clavin, Christopher T; 'ldacus@ida.org'
Subject: Methan S&T Needs Activities

Colleagues,

I'm attaching the activities we've received collected in one document. Thank you everyone for the great summaries. I look forward to speaking to those of you who can make it at 2 ET. Most of the time will be for agency updates. Here is a rough agenda. If anyone has other items they'd like to raise, let me know and I can allocate time.

Ex. 5 - Deliberative Process

Best,

Austin

Austin L Brown, Ph.D.

Senior Policy Analyst

Executive Office of the President

Office of Science and Technology Policy

Ex. 6 - Personal Privacy

To: Staudt, Amanda[AStaudt@nas.edu]; Irving, Bill[Irving.Bill@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]
Cc: Thomas, Katherine C[KCThomas@nas.edu]; Hargrove, Anne[Hargrove.Anne@epa.gov]
From: Gunning, Paul
Sent: Thur 10/15/2015 1:08:06 PM
Subject: RE: Methane study - next steps

Thanks Amanda. If it works for you, maybe we can set up a time next week to catch up on this (phone call is fine). If that works for you, please let us know what days/times might work. I am copying Anne Hargrove who can help set this up.

Thanks

Paul

From: Staudt, Amanda [mailto:AStaudt@nas.edu]
Sent: Wednesday, October 14, 2015 9:37 AM
To: Gunning, Paul; Irving, Bill; Weitz, Melissa
Cc: Thomas, Katherine C
Subject: Methane study - next steps

Good Morning, Paul, Bill, and Melissa,

I'm pleased to share that the Academies have formally approved the prospectus for the study on methane emissions, reporting, and inventories! I attached the latest version for you.

Dr. Cicerone had three suggestions:

1) Consider how to estimate the aggregate uncertainties in measuring and otherwise quantifying anthropogenic methane emissions;
2) Consider international studies and contributions to research in this area; and
3) Consider studies pertaining to use of isotopic tracers.

My feeling is that all three of these topics could already be addressed within the scope delineated by the current Statement of Task, but it may be useful to include some explicit mention of them in the background context to draw the committee's attention to these issues. Okay by you?

We can now move on to the proposal phase. Please let us know how you would like to proceed. We can be pretty flexible about different funding vehicles, so will try to do whatever is easiest for you. It's possible that the Academies have an IDIQ contract in place with EPA already, which can be a convenient option. I'll ask around to see what might be available.

As you know NOAA has also agreed to contribute funding to the study, likely in the range of $400K. I'll be reaching out to DOE, NSF, NASA, and USDA, and possibly to some private foundations, to see if they have interest in joining as sponsors. Please let us know if you have any concerns about us approaching other sponsors and/or if you have other suggestions of who to approach.

Finally, let us know if there's anything we should be considering in terms of the timing of the study – i.e., is there any reason why we should try to expedite the proposal phase, or is it okay if we let things proceed at a regular pace? Note that we need 70% in hand ($565K in this case) and to be pretty confident that the remainder will be forthcoming in order to begin work.

Let us know if it would be easier to talk through some of these issues on the phone or in person. I figured it would be helpful to do a quick brain dump here, and then we can figure out how best to proceed.

Thanks so much!

Amanda

Amanda Staudt, Ph.D., Director

Board on Atmospheric Sciences and Climate

Polar Research Board

The National Academies of Sciences, Engineering, and Medicine

(202) 334-1245

http://dels.nas.edu/basc

http://dels.nas.edu/prb

To: Tom Moore[tmoore@westar.org]
Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]
From: McKittrick, Alexis
Sent: Thur 6/18/2015 2:20:19 PM
Subject: RE: encouraging Operators to use 2014 "Deferred Data" reports to complete WRAP O&G Emission Inventory surveys in selected Western Basins

Tom,

Thanks for your note and your voicemail from late yesterday. It looks like Melissa and I can be available for a call at 2:30PM eastern today. Does that work for you? If so, do you want us to just call your office number at that time? I can set up a conference call line, if you'd like to include others.

Regards,

Alexis

Alexis McKittrick, Ph.D.

Climate Change Division

U.S. Environmental Protection Agency

Phone: 202-343-9153

E-mail: mckittrick.alexis@epa.gov

From: Tom Moore [mailto:tmoore@westar.org]
Sent: Wednesday, June 17, 2015 3:58 PM
To: McKittrick, Alexis
Cc: Weitz, Melissa
Subject: encouraging Operators to use 2014 "Deferred Data" reports to complete WRAP O&G Emission Inventory surveys in selected Western Basins

Importance: High

Hello, Alexis and Melissa – I wondered if I could talk with you both, or at least Alexis on the Subpart W "Deferred Data" reporting by Operators for 2014. We have a couple or 3 survey-based O&G EIs in process for 2014 data, including all GHGs, and expect we will hear from the Operators that they had to report the Deferred Data by April 1, 2015. We'd like to modify our spreadsheet survey (example attached) so Operators can give us Subpart W data referenced to the "Sub-basins" we define.

Like to chat with you both if possible about this idea and help me prepare for the onslaught of "too much duplicate reporting" comments we expect and if this would be helpful to Subpart W data analysis and GHG EI efforts by EPA.

It would be great to talk this afternoon so you can think about my questions before answering. Thanks in advance.

Tom Moore, WRAP Air Quality Program Manager

Western States Air Resources Council (WESTAR) | e: tmoore@westar.org | o: 970.491.8837

Western Regional Air Partnership | www.wrapair2.org

From: Tom Moore
Sent: Tuesday, June 16, 2015 4:17 PM
To: Tom Moore
Subject: FW: Slides for tomorrow's National Oil and Gas Emissions Committee call

Tom Moore, WRAP Air Quality Program Manager

Western States Air Resources Council (WESTAR) | e: tmoore@westar.org | o: 970.491.8837

Western Regional Air Partnership | www.wrapair2.org

From: Gibbs, Mark [mailto:Mark.Gibbs@deq.ok.gov]
Sent: Wednesday, February 11, 2015 3:26 PM
To: 'airstar0077@gmail.com'; 'akcarter@adem.state.al.us'; 'amanda.l.davis@tn.gov'; 'ASadar@achd.net'; 'avickers@marama.org'; 'Beeler.Cindy@epa.gov'; 'brett.davis@wyo.gov'; 'brian.bohlmann@wyo.gov'; 'buzz.asselmeier@illinois.gov'; 'Byeong.Kim@dnr.state.ga.us'; Schroeder, Carrie; Garbe, William (Cooper); 'Cozzie.David@epa.gov'; 'curtis.taipale@state.co.us'; 'cwoods@csg.org'; 'dale.wells@state.co.us'; 'DALEBOUTR@michigan.gov'; 'darla.potter@wyo.gov'; 'Dewees.Jason@epa.gov'; Dan Johnson; 'ektrythall@nd.gov'; 'Erica.Fetty@epa.state.oh.us'; 'fcook@blm.gov'; 'Frantz.Chris@epa.gov'; 'gabrielle.petron@noaa.gov'; 'gary.reinbold@deq.idaho.gov'; 'Glover.Ed@epa.gov'; 'greg.lauderdale@tceq.texas.gov'; 'heather.sands@ncdenr.gov'; 'Holly.Ferguson@tceq.texas.gov'; 'hosford.chip@epa.gov'; 'Houyoux.Marc@epa.gov'; 'janssen@ladco.org'; 'Jim.Price@tceq.texas.gov'; 'JMCDILL@marama.org'; Kalfas, Joshua L.; 'jsemerad@nd.gov'; 'kaleri.cynthia@epa.gov'; 'karin.landsberg@alaska.gov'; 'Kathy.Pendleton@tceq.texas.gov'; 'kgee@pa.gov'; 'Koerber.Mike@epa.gov'; 'LDeahl@kdheks.gov'; 'lisa.ehrhart@deq.virginia.gov'; 'Lundelius.Diana@epa.gov'; 'Macpherson.Alex@epa.gov'; 'mark.jones@state.nm.us'; 'Mark.McMillan@dphe.state.co.us'; 'Mason.Rich@epa.gov'; 'masond1@michigan.gov'; 'McKittrick.Alexis@epa.gov'; 'michael.abraczinskas@ncdenr.gov'; 'Michael.Ege@tceq.texas.gov'; 'michael.trahiotis@ct.gov'; 'mike.pring@erg.com'; 'mike.schneider@state.nm.us'; 'Mindy.Hendrickson@wv.gov'; 'Moore.Bruce@epa.gov'; 'muhl@blm.gov'; 'nam.ed@epa.gov'; 'Nicholle.Worland@dep.state.nj.us'; 'oppapage@gw.dec.state.ny.us'; 'Page.Steve@epa.gov'; 'patricia_f_brewer@nps.gov'; 'pbarickman@utah.gov'; 'Rachel.Melton@tceq.texas.gov'; 'Ray.Papalski@dep.state.nj.us'; 'Regi.Oommen@erg.com'; 'riddick.lee@epa.gov'; 'Robert.J.Betterton@wv.gov'; 'rsmartin@nd.gov'; 'sarah.clouse@ecy.wa.gov'; 'sbogart@pa.gov'; 'Schell.Bob@epa.gov'; 'Shores.Richard@epa.gov'; 'Snyder.Jennifer@epa.gov'; 'sushma.masemore@ncdenr.gov'; 'szelinka@arb.ca.gov'; 'tcfoster@deq.virginia.gov'; 'Terry.Sara@epa.gov'; 'Thoma.Eben@epa.gov'; Tom Moore; 'tnguyen@arb.ca.gov'; Richardson, Thomas M.; 'tom.velalis@epa.state.oh.us'; 'Tonnesen.Gail@epa.gov'; Theresa Pella; 'Tsirigotis.Peter@epa.gov'; 'tune@adeq.state.ar.us'; 'twallace@mde.state.md.us'; 'Waltzer.Suzanne@epa.gov'; 'Wayland.Richard@epa.gov'; 'Weitz.Melissa@epa.gov'; 'wilbanmc@dhec.sc.gov'; 'Witosky.Matthew@epa.gov'; 'Wortman.Eric@epa.gov'; 'woswald@utah.gov'; 'young.carl@epa.gov'; 'Zubrow.Alexis@epa.gov'; 'Fry, Jessica'; 'Smith, James-D'; 'Wong.Richard@epa.gov'; 'stackhouse.debbie@epa.gov'; 'tammy.manning@ncdenr.gov'; 'james.r.smith@tn.gov'; 'paige.sprague@tceq.texas.gov'
Subject: Slides for tomorrow's National Oil and Gas Emissions Committee call

Slides for tomorrow's GHGRP presentation plus responses to the questions from the committee about the GHGRP and Flight are attached.

Will look forward to talking with you tomorrow at 2 pm Eastern.

Mark

From: Gibbs, Mark
Sent: Tuesday, February 10, 2015 9:38 AM
Subject: National Oil and Gas Emissions Committee - Thursday, February 12, 2015 Meeting Reminder

Hi All:

Attachments to this email:

•□□□□□□□□ Minutes of January 2015 Meeting

•□□□□□□□□ Compilation of Questions about GHGRP, e-GGRT, Flight, etc. (to be discussed in Agenda Item 2)

Meeting Time: **2:00 – 3:30 pm** Eastern, Thursday, February 12, 2015

Call-in number: Ex. 5 - Deliberative Process

Confirmation Number: Ex. 5 - Deliberative Process

1. Approve minutes of January meeting

2. GHGRP O&G data: Current Subpart W data elements – Alexis McKittrick (slides to follow)

3. Comment Period for Subpart W 2015 Revisions Proposals – now extended to Tuesday, February 24, 2015

Submit comments at http://www.regulations.gov/#!docketDetail;D=EPA-HQ-OAR-2014-0831

4. Public training webinar on using Facility Level Information on Greenhouse Gases Tool (FLIGHT), 3-4 pm, March 3, 2015

Register at https://attendee.gotowebinar.com/register/226726258870718465

5. Update on Public Review Draft of GHG National Inventory – Melissa Weitz

6. Colorado School of Mines Workshop on reconciliation of top-down and bottom-up methane emissions estimates, Denver Airport Marriott, February 24-25, 2015

7. Ways to improve speciation of O&G VOC emissions for AQ modeling – Alexis Zubrow

8. Recap of OAQPS call from January 28 on EPA's strategy on reducing methane and VOC's from the oil and natural gas industry

9. Reminder about O&G events at the 2015 International Emission Inventory Conference

10. Next meeting Thursday, March 12 at 2:00 pm – 3:30 pm Eastern, same call in number and confirmation number

Talk to you on Thursday,

Mark

Mark Gibbs

Emission Inventory Manager

Oklahoma DEQ

(405) 702-4179

To: Beeler, Cindy[Beeler.Cindy@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]
Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]
From: McKittrick, Alexis
Sent: Thur 12/10/2015 9:32:39 PM
Subject: RE: Source of Pneumatic Controller Emission Factors in Table W-1A?
2010 final rule TSD.pdf

Cindy,

The reference and background for how these emission factors are developed is typically found in the Technical Support Documents (TSDs) for our Subpart W rules. I've attached the most relevant one to your question, which is the TSD for the original 2010 finalization of Subpart W. See the appendices for details on how the population emission factors were developed.

As an aside, we are also working on an internal memo summarizing the background and references for the current pneumatic device emission factors, which will be easier reading than making folks dig through TSDs. That may not be ready until after the holidays, but I wanted to let you know it is coming. Note that we currently don't plan to send it outside the agency though.

Best,

Alexis

From: Beeler, Cindy
Sent: Wednesday, December 09, 2015 4:25 PM
To: McKittrick, Alexis <McKittrick.Alexis@epa.gov>; DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>
Subject: Source of Pneumatic Controller Emission Factors in Table W-1A?

Alexis & Mark –

In an effort to get our RARE Grant Team prepared to eventually compare our measurements (activity count and emission rates) to other data, I included the GHGRP-

W emission factors. Can you provide the source of the default emission factors you provide in Table W-1A?

TABLE W–1A TO SUBPART W OF PART 98—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION FACILITIES AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING FACILITIES

Onshore petroleum and natural gas production and Onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
Eastern U.S.	
Population Emission Factors—All Components, Gas Service [1]	
Valve	0.027
Connector	0.003
Open-ended Line	0.061
Pressure Relief Valve	0.040
Low Continuous Bleed Pneumatic Device Vents [2]	1.39
High Continuous Bleed Pneumatic Device Vents [2]	37.3
Intermittent Bleed Pneumatic Device Vents [2]	13.5
Pneumatic Pumps [3]	13.3
Population Emission Factors—All Components, Light Crude Service [4]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-ended Line	0.05
Pump	0.01
Other [5]	0.30
Population Emission Factors—All Components, Heavy Crude Service [6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003

TABLE W–1A TO SUBPART W OF PART 98—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION FACILITIES AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING FACILITIES—Continued

Onshore petroleum and natural gas production and Onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
Open-ended Line	0.006
Other[5]	0.003
Population Emission Factors—Gathering Pipelines, by Material Type[7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60
Western U.S.	
Population Emission Factors—All Components, Gas Service[1]	
Valve	0.121
Connector	0.017
Open-ended Line	0.031
Pressure Relief Valve	0.193
Low Continuous Bleed Pneumatic Device Vents[2]	1.39
High Continuous Bleed Pneumatic Device Vents[2]	37.3
Intermittent Bleed Pneumatic Device Vents[2]	13.5
Pneumatic Pumps[3]	13.3
Population Emission Factors—All Components, Light Crude Service[4]	
Valve	0.05
Flange	0.003
Connector (other)	0.007
Open-ended Line	0.05
Pump	0.01
Other[5]	0.30
Population Emission Factors—All Components, Heavy Crude Service[6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other[5]	0.003
Population Emission Factors—Gathering Pipelines by Material Type[7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60

[1] For multi-phase flow that includes gas, use the gas service emissions factors.
[2] Emission Factor is in units of "scf/hour/device."
[3] Emission Factor is in units of "scf/hour/pump."
[4] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."
[5] "Others" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.
[6] Hydrocarbon liquids less than 20°API are considered "heavy crude."
[7] Emission factors are in units of "scf/hour/mile of pipeline."

Thanks,

Cindy Beeler
US EPA Region 8, Energy Advisor
Office of the Regional Administrator
Tel: 303-312-6204
Beeler.Cindy@epa.gov

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To: Bylin, Carey[Bylin.Carey@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]
Cc: Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]
From: McKittrick, Alexis
Sent: Wed 12/2/2015 5:19:02 PM
Subject: Subpart W proposal outreach doc for Paul
Communications_strategy_W leak detection rule 12_2_15 clean.docx
Communications_strategy_W leak detection rulecb mdf AM.docx

Carey & Mark,

Attached is the Subpart W leak detection proposal outreach strategy that I plan to give Paul at 1PM. Thank you for your edits and thoughts on this document. I have also attached a version with all the changes tracked for your reference.

Regards,

Alexis

Alexis McKittrick, Ph.D.

Climate Change Division

U.S. Environmental Protection Agency

Phone: 202-343-9153

E-mail: mckittrick.alexis@epa.gov

To: DeLuca, Isabel[DeLuca.Isabel@epa.gov]
Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]
From: Gunning, Paul
Sent: Fri 7/17/2015 7:46:22 PM
Subject: RE: 7/21 - Conference on methane

Yes, thanks Isabel! Copying Melissa in case she has additional info. for you.....

Paul

From: DeLuca, Isabel
Sent: Friday, July 17, 2015 3:43 PM
To: Gunning, Paul
Subject: FW: 7/21 - Conference on methane

I saw on your calendar EDF is coming in on Monday to speak with you, Joe, et al about their new study. Looks like they're doing a public webinar on Tuesday morning. I'm guessing we may get some press questions (I'll pull out the usual response…).

From: Jones, Enesta
Sent: Friday, July 17, 2015 3:10 PM
To: Purchia, Liz; Harrison, Melissa; Lee, Monica; Davis, Alison; Dennis, Allison; DeLuca, Isabel
Cc: AO OPA Media Relations
Subject: FYI: 7/21 - Conference on methane

1. 10:00 AM EDT

Teleconference on methane emissions study

o Researchers will hold a teleconference to discuss the findings of a new paper quantifying nationwide methane emissions from the U.S. natural gas transmission and storage sector. Call: Ex. 5 - Deliberative Process Conference ID: Ex. 5 - Deliberative Process View the webinar here.

o **Contact**

Anna Geismar, Ex. 6 - Personal Privacy, ageismar@edf.org.

Hide Details **Export to Calendar**

Enesta Jones

U.S. EPA, Office of Media Relations

Desk: 202.564.7873

Cell: 202.236.2426

To: Irving, Bill[Irving.Bill@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; Franklin, Pamela[Franklin.Pamela@epa.gov]
From: Gunning, Paul
Sent: Tue 11/17/2015 1:50:39 PM
Subject: FW: SAVE-THE-DATE: JISEA Webinars on Natural Gas Methane Inventory Improvement, New Report

FYI.....

From: Meixner , Debbie [mailto:Debbie.Meixner@jisea.org] **On Behalf Of** Arent, Doug
Sent: Monday, November 16, 2015 5:36 PM
To: JISEA Coordinator <jisea.coordinator@jisea.org>
Cc: Heath, Garvin <Garvin.Heath@nrel.gov>; Meixner , Debbie <Debbie.Meixner@jisea.org>
Subject: SAVE-THE-DATE: JISEA Webinars on Natural Gas Methane Inventory Improvement, New Report

Dear colleague

I am pleased to invite you to participate in one of two webinar briefings on a recent report from the Joint Institute for Strategic Energy Analysis of the National Renewable Energy Laboratory, entitled:

Estimating Methane Emissions from the Natural Gas Supply Chain: Approaches, Uncertainties, Current Estimates and Future Studies

The report summarizes current estimates of methane emissions from the natural gas sector in the United States Greenhouse Gas Inventory, analyzing the sources, uncertainties, and identifying opportunities for improvement to accuracy from new bottom-up and top-down measurement studies. You can view and download the report here: http://www.nrel.gov/docs/fy16osti/62820.pdf.

The webinar will last 1 hour, with opportunity for discussion. It will be offered once before and once after Thanksgiving to accommodate varying schedules.

1. November 24: 10-11 am MT (noon ET and 9 am PT). Please register for this webinar at https://attendee.gotowebinar.com/register/3568490647327926785 (After registering, you will receive a confirmation email containing information about joining the webinar).

2. November 30: 2-3 pm MT (4-5 ET, 1-2 PT). Please register for this webinar at https://attendee.gotowebinar.com/register/4021522423320629249 (After registering, you will receive a confirmation email containing information about joining the webinar).

My assistant, Debbie Meixner, will send a calendar invitation with the registration link for each of the above webinars. Please remember to register for the webinar and please feel free to forward the registration link to other individuals within your organization.

On behalf of the authors (Garvin Heath, Ethan Warner, Daniel Steinberg and Adam Brandt of Stanford University), I hope this report provides useful insights regarding inventory-based estimates of methane emissions from natural gas systems and how the work you might conduct or fund could be used for inventory improvement. We would like thank the US Department of Energy's Office of Energy Policy and Systems Analysis (EPSA) for their support of this research. Apologies for cross postings; feel free to forward the invitation to others who may be interested in the report or webinar.

Please feel free to contact me if you have any questions.

Thank You!

Doug Arent

To: Millett, John[Millett.John@epa.gov]; DeLuca, Isabel[DeLuca.Isabel@epa.gov]; Dennis, Allison[Dennis.Allison@epa.gov]
Cc: Drinkard, Andrea[Drinkard.Andrea@epa.gov]; Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]
From: Gunning, Paul
Sent: Mon 12/7/2015 5:40:52 PM
Subject: RE: Methane Talking Points

Thanks John!

From: Millett, John
Sent: Monday, December 07, 2015 12:29 PM
To: DeLuca, Isabel <DeLuca.Isabel@epa.gov>; Dennis, Allison <Dennis.Allison@epa.gov>
Cc: Drinkard, Andrea <Drinkard.Andrea@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; Kocchi, Suzanne <Kocchi.Suzanne@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>; DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>
Subject: RE: Methane Talking Points

Thanks – Looks good – I'll attach this file to Paul's response to Janet from this morning with a brief note on status, etc. The 3rd to last bullet summarizes the desk statement nicely, and Janet and the administrator already have 2-pagers on O&G regs, so think we're covered.

From: DeLuca, Isabel
Sent: Monday, December 07, 2015 12:04 PM
To: Millett, John <Millett.John@epa.gov>; Dennis, Allison <Dennis.Allison@epa.gov>
Cc: Drinkard, Andrea <Drinkard.Andrea@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; Kocchi, Suzanne <Kocchi.Suzanne@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>; DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>
Subject: RE: Methane Talking Points

Hi John,

Here are some bullets on the Barnett Shale study. We haven't seen the paper yet, so we are going from what EDF told us in the presentation last week. You already have the short desk statement for this, which recycles our previous press responses on EDF studies.

Can you please help usher this up the chain?

Let us know if you need anything else!

Best,

isabel

From: Millett, John
Sent: Monday, December 07, 2015 9:10 AM
To: Dennis, Allison <Dennis.Allison@epa.gov>; DeLuca, Isabel <DeLuca.Isabel@epa.gov>
Cc: Drinkard, Andrea <Drinkard.Andrea@epa.gov>
Subject: Fwd: Methane Talking Points

FYI

John Millett

202.510.1822

Begin forwarded message:

> **From:** "Gunning, Paul" <Gunning.Paul@epa.gov>
> **Date:** December 7, 2015 at 5:20:25 AM EST
> **To:** "McCabe, Janet" <McCabe.Janet@epa.gov>
> **Cc:** "Goffman, Joseph" <Goffman.Joseph@epa.gov>, "Dunham, Sarah" <Dunham.Sarah@epa.gov>, "Tsirigotis, Peter" <Tsirigotis.Peter@epa.gov>, "Millett, John" <Millett.John@epa.gov>, "Drinkard, Andrea" <Drinkard.Andrea@epa.gov>
> **Subject: Re: Methane Talking Points**
>
> No problem we will send something later this AM
>
> Paul
>
> Paul M Gunning
>
> 202-251-1436
>
> On Dec 7, 2015, at 12:55 AM, McCabe, Janet <McCabe.Janet@epa.gov> wrote:
>
> > Yes please. The question might come to one of in Paris as well, so please send along whatever you come up with.

Thanks

Sent from my iPhone

On Dec 7, 2015, at 12:16 AM, Goffman, Joseph <Goffman.Joseph@epa.gov> wrote:

Please note Candace request. Presumably we will want to have some kind of response ourselves. Apologies is this is already in circulation and I am whiffing on it. Thanks

- Joseph Goffman

Sent from my iPhone

Begin forwarded message:

From: "Vahlsing, Candace" <Ex. 6 - Personal Privacy>
Date: December 6, 2015 at 6:04:20 PM EST
To: "'McCabe.Janet@epa.gov'" <McCabe.Janet@epa.gov>, "'Goffman.Joseph@epa.gov'" <Goffman.Joseph@epa.gov>
Cc: "Utech, Dan G." Ex. 6 - Personal Privacy
Subject: Methane Talking Points

Hi Janet and Joe,

I hope you both are having a good weekend. On Friday, EDF briefed us on their NAS methane measurement study that is set to be released tomorrow. This is the one where they found that emissions in the Barnett are substantially higher than those reported in the inventory/GHGRP. They said they briefed Paul too. Do you guys have talking points you could share that explain/provide rationale for the discrepancy? We only need super toplines.

Many thanks,

Candace

To: Ronchi,Alisa [NCR][Alisa.Ronchi@ec.gc.ca]
Cc: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Cook, BrianB[Cook.BrianB@epa.gov]
From: McKittrick, Alexis
Sent: Tue 5/12/2015 8:59:26 PM
Subject: RE: Follow up to the webinar
EPA GHG Inventory oil and gas overview 5_7_15.pdf
EPA GHGRP oil and gas overview 5_7_15.pdf

Hi Alisa,

Thanks for the follow-up note. Attached are the presentations from our webinar with you all last week, which includes slides on the EPA's Greenhouse Gas Reporting Program and the EPA's Greenhouse Gas Inventory. The EPA participants were:

Alexis McKittrick, EPA's Greenhouse Gas Reporting Program, mckittrick.alexis@epa.gov, 202-343-9153

Melissa Weitz, EPA's Greenhouse Gas Inventory, weitz.melissa@epa.gov, 202-343-9897

Brian Cook, EPA's Greenhouse Gas Reporting Program, cook.brianb@epa.gov, 202-343-9135

Mark DeFigueiredo, EPA's Greenhouse Gas Reporting Program, defiguieredo.mark@epa.gov, 202-343-9928

Follow-up questions on the EPA GHGRP can come to me and questions on the GHG Inventory should go to Melissa. I will send David's contact information on to our EPA e-GGRT team leader, Kong Chiu. He should be in touch in the near future.

We would also like to take you all up on the offer to do a similar overview of Environment Canada's GHG reporting program and GHG inventory. Let us know when would be a good date / time for you all. We aren't in a big rush, but it would be helpful to do the webinar by mid-June, if possible.

Regards,

Alexis

Alexis McKittrick, Ph.D.

Climate Change Division

U.S. Environmental Protection Agency

Phone: 202-343-9153

E-mail: mckittrick.alexis@epa.gov

From: Ronchi,Alisa [NCR] [mailto:Alisa.Ronchi@ec.gc.ca]
Sent: Tuesday, May 12, 2015 12:18 PM
To: McKittrick, Alexis
Subject: FW: Follow up to the webinar

HI Alexis,

In Mark's absence, would you be able to send me the presentation and a list of EPA participants from Thursdays GHG Reporting Webinar? Also, David Yip (EC) would like to speak with you regarding e-GGRT. He can be reached at 416-739-4409 or by email at david.yip@ec.gc.ca.

Feel free to give me call if you need anything from our end.

Thanks,

Alisa Ronchi

819-420-7922

Oil, Gas and Alternative Energy Division

Division de pétrole, gaz et énergie de remplacement

Environment Canada / Environnement Canada

To: Weitz, Melissa[Weitz.Melissa@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; Bylin, Carey[Bylin.Carey@epa.gov]; Franklin, Pamela[Franklin.Pamela@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]
From: Gunning, Paul
Sent: Thur 6/25/2015 7:55:22 PM
Subject: FW: M.J. Bradley & Associates: Environmental Energy Insights - Spring 2015
MJBA Insights Spring 2015.pdf

FYI

From: Pye Russell [mailto:prussell@mjbradley.com]
Sent: Thursday, June 25, 2015 11:48 AM
To: Pye Russell
Subject: M.J. Bradley & Associates: Environmental Energy Insights - Spring 2015

Attached please find the Spring 2015 edition of *Environmental Energy Insights*. This issue includes articles on electric vehicles, methane emissions from natural gas distribution systems, and emissions allowance allocation options.

Environmental Energy Insights

Spring 2015

EVs by the Numbers (Part 1)

Today there are more plug-in electric vehicle (PEV) models available from major auto manufacturers than there have ever been, and a growing number of PEVs on the road. Despite this, major challenges to greater PEV adoption remain, including high cost, limited range between charges, and lack of public charging infrastructure. Some utilities see PEVs as an opportunity, particularly in the face of growing distributed generation, but depending on how they are charged, greater PEV penetration could also increase peak loads and require costly infrastructure upgrades. This article is the first in a series that will examine the potential effects of PEVs on electric utilities, starting with a summary of the current state of the U.S. PEV market, lessons learned about consumer charge behavior from PEV pilot programs, and lessons learned from utility pilot programs to test alternative PEV charging rates.

Estimates of Methane Emissions from Natural Gas Distribution Systems

As the Obama Administration and EPA focus on reducing total U.S. methane emissions (see Methane Strategy Update in the Summer 2014 issue of Insights), stakeholders have shown increased interest in EPA's methodologies for estimating methane emissions from natural gas systems. While EPA has made

a number of updates to how it calculates emissions from certain upstream natural gas sources in the annual Greenhouse Gas Inventory, its methodology for distribution systems remains unchanged. A recent study by Washington State University provides data that EPA could use to update its current assumptions. This article compares EPA's estimates for methane emissions to the Washington State University study.

Allowance Allocation 101

Under EPA's proposed Clean Power Plan (CPP), states have the option of adopting either a rate-based target—expressed in CO_2 pounds per megawatt hour—or a mass-based target in tons per year; they also have broad discretion in designing the programs and policies included as part of their compliance plan. There are pros and cons with the various options available, and states will need to carefully consider their decisions once EPA publishes the final numbers. Given the interest that states and stakeholders have expressed for mass-based targets and mass-based trading programs, we thought it would be helpful to compile a refresher on the options available to states for distributing emission allowances under a mass-based trading program. The distribution of emissions allowances has always been a controversial topic going back to the Acid Rain SO_2 trading program, and is certain to be a topic for debate for states that choose to go down this path.

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Finding the ways that work

January 2016

RISING RISK:
Improving Methane Disclosure in the Oil and Gas Industry

EMBARGOED UNTIL 8AM EST JANURY 14TH, 2016

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ABOUT THIS REPORT

This report demonstrates the need for investors to pay greater attention to methane emissions from the oil and gas industry and advocate better disclosure practices on this emerging issue. As scrutiny increases, methane presents short-term risks to investments in the oil and gas industry in the form of economic losses and existing and future regulations. The longer-term prospects for natural gas to play a credible role in the transition to a clean energy global economy are threatened by methane emissions.

It is well documented that there are practical and cost-effective solutions to minimize methane emissions, many of which will increase the bottom line for companies. Our hope is that investors will read this report and take the opportunity to engage constructively with companies to ensure the industry is appropriately handling this issue. Doing so will have the benefitsof decreasing risk and improving operational efficiencywhile making oil and gas companies more sustainable and more profitable.

While the primary audience for this paper is investors, we also provide a number of recommendations for oil and gas operators and disclosure platforms on how they too can improve the state of methane disclosure.

ABOUT ENVIRONMENTAL DEFENSE FUND

Environmental Defense Fund (EDF) is one of the world's largest environmental nonprofitorganizations, with more than one million members and a staff of 500 scientists, economists, policy experts, and other professionals around the world. EDF findspractical and lasting solutions to the most serious environmental problems. Working with leading businesses, scientists and academics, EDF is taking a leading role in minimizing the environmental and health risks associated with the development of oil and natural gas.

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thinkPARALLAX designed and produced the finalreport.

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Foreword

JANUARY 11, 2016

As the nation's largest educator-only public pension fund managing over $185 billion in assets, the California State Teachers' Retirement System (CalSTRS) is well aware of the substantial risk that climate change poses to the economy, corporate bottom lines and investor portfolios. As a matter of fiduciaryduty, we are escalating our attention on this pivotal issue, while working to ensure that the many companies we own are doing the same.

Potent methane emissions from the oil and gas industry pose a burden on the climate and a risk to the industry's reputation, while also representing waste of a valuable product. Therefore, enhanced methane management is both a risk-mitigation imperative and a financial opportunity. Improving methane emission disclosure is a key step toward securing investor confidence, managing risk and unlocking returns.

As a shareholder with a global portfolio, CalSTRS has a financialstake in the long-term performance of the natural gas industry. However, for the gas industry to be part of the solution in the needed transition to a low-carbon global economy, methane emissions — which literally leak away the potential climate benefitsof natural gas over other fossil fuels — must be actively managed. Improved methane emission disclosure is one important piece of the climate change risk management puzzle.

Rising Risk: Improving Methane Disclosure in the Oil and Gas Industry is a valuable contribution to the dialogue about climate solutions, offering fresh insights for investors along with a valuable roadmap for improved disclosure. The data-driven analysis in *Rising Risk* underscores the need for improvement in methane emissions disclosure to address reputational risk, regulatory risk and economic waste. CalSTRS believes that the use of a core set of streamlined methane metrics to improve transparency will contribute to improved risk management for the industry. Improving methane management and related disclosure will also help companies maximize operational efficiencies, get ahead of upcoming regulations and do their part to address climate change.

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Managing methane emissions is a critical part of the urgent challenge of addressing climate change. In keeping with our fiduciaryduty, CalSTRS will encourage oil and gas operators to embrace improved methane emissions disclosure as a win-win opportunity to mitigate risk, build trust and create long-term shareholder value.

Jack Ehnes
Chief Executive Officer
California State Teachers' Retirement System

Executive Summary

Voluntary reporting on methane emissions by the oil and gas industry is poor — less than a third of reviewed companies report emissions and zero companies disclose emissions reduction targets **making it challenging for investors to effectively gauge materiality, assess performance and manage risk.**

Methane, the primary component of natural gas, is a climate pollutant 84 times more powerful than carbon dioxide over a 20 year period, and it is responsible for a quarter of the warming we are experiencing today.[1]

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Emissions from the oil and natural gas industry represent the largest industrial source of methane emissions, both in the United States and globally.[2] Methane emissions undermine the value proposition of natural gas for delivering cleaner, low-cost energy, and have drawn increasing scrutiny from the public, environmental and health groups, and state and federal policymakers. Additionally, emissions of methane represent wasted saleable product, with implications for operational efficiency and the bottom line. Unfortunately, reporting of methane emissions by the industry is lacking, making it challenging for investors to effectively understand the materiality of the problem, assess performance and manage risk.

Benefits of Methane Emissions Data

Improved transparency is required to enable investor management of three key risks:

- **Economic:** Emissions of methane, the main component of natural gas, represent a loss of resources that directly impact topline revenue. Estimates suggest that as much as $30 billion of natural gas is emitted into the atmosphere each year globally, with $2 billion lost annually in the U.S. alone.[3] Low-cost solutions exist to reduce these emissions, many of which come with a positive payback.[4] Understanding company methane management practices and results can serve as a proxy for operational efficiency.[5]
- **Regulatory:** Regulators at the state and federal level are beginning to institute standards to limit methane emissions. Methane emissions information can help investors understand a company's exposure and how easily it can comply with regulations as they are implemented.
- **Reputational:** Methane emissions are a long-term reputational risk for the industry. Methane reduces the climate benefits of natural gas and thus undermines its ability to hasten the transition towards a lower-carbon economy. Better data can help investors understand how industry is addressing this issue.

This report has three purposes: (1) to educate oil and gas investors on the importance of methane emissions, (2) examine and document the current state of reporting on methane in the U.S. oil and gas sector and (3) provide recommendations to improve the amount, quality, and accuracy of methane emissions data.

The Current State of Methane Reporting is Inadequate

To understand the current state of reporting, EDF conducted an analysis of 40 of the largest U.S. oil and gas producers, as well as 25 large midstream companies. We reviewed primary sources of information for investors and other stakeholders, including SEC filings, CDP questionnaires, sustainability reports and company websites. The primary findings include:

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- **Zero companies disclose reduction targets, and few report methane-related data.** Of the 65 companies, only 18 reported their methane emissions. Even fewer companies provided detailed information on how they are managing their emissions. Zero companies provided quantitative reduction targets, and one company provided comprehensive information regarding their leak detection and repair (LDAR) programs. A positive correlation between size of companies and quality of disclosure suggests the state of disclosure among the smaller companies not within the scope of this report may be even worse.
- **The quality of disclosure is low, limiting usefulness for decision-making.** Among companies that disclose emissions, reports contain vague, qualitative information that is not actionable. The qualitative and highly variable nature of corporate disclosures limits meaningful assessments of, and comparisons between, individual companies. Furthermore, companies measure their emissions in a variety of ways, primarily using estimates, which diminishes the accuracy of data.
- **The lack of rigorous and standardized metrics hampers disclosure quality.** Across the various disclosure platforms, each has a different methodology for how companies should report their methane information. This inconsistency limits the comparability of data.

Recommendations: A New Approach to Reporting Can Improve Transparency

Based on the challenges with current reporting, three areas must be addressed to improve methane disclosure:

METRICS

Investors need rigorous, accurate and comparable information to assess company performance. Unlike in financial reporting, no standardized metrics currently exist for methane emissions. EDF, with input from investors and operators, has developed a set of methane metrics. These metrics will make data more actionable and aid in the assessment of methane performance. We recommend that operators utilize the metrics as performance indicators to drive operational improvements, investors use metrics to assess performance and manage risk, and disclosure platforms incorporate the metrics in their questionnaires and methodologies.

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- **Emission Rate —** Emission rate refers to the percentage of total methane volume which is being lost as a function of production or throughput — a single methane intensity figure. By reporting emissions as a percentage, the resulting data becomes comparable between companies, regardless of size, and over time, as a given company's operations evolve.
- **Reduction Targets —** Goal setting is the most basic and effective management device for improving performance. Emission reduction goals and timelines provide actionable information about management commitment to reduce emissions.
- **LDAR Protocol —** Operators should report the frequency, methodology and scope of their leak detection and repair (LDAR) programs. LDAR is one of the most important ways for a company to reduce emissions, so understanding how a company approaches LDAR can help investors gauge how effectively a company is reducing emissions.
- **Economic Value of Methane Emissions —** Expressing methane emissions as a dollar value allows investors to easily understand the potential financial impact of wasted natural gas.

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ACCURACY

The accuracy of reported methane data can be improved. Companies often use emission estimates that may be based on outdated information and thus not reflective of actual emissions. Companies should strive to utilize direct measurement of emissions, particularly for fugitive emissions.[6] In general, companies should ensure that their measurement is comprehensive, based on frequent observation and employs rigorous quantification.

PLATFORMS

While the Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP), a compliance reporting program, has substantial information on methane emissions for U.S. facilities, there are several limitations to the program that hinder its usefulness for investors. Organizations like CDP, Sustainability Accounting Standards Board (SASB), and Global Reporting Initiative (GRI) have developed to fulfilling investors' growing desire

(ESG) data such as methane, into their decision-making processes. Operators should utilize these platforms. In turn, the organizations must elevate the methane component of their reporting platforms, and improve it by using key methane metrics to harmonize standards, improve comparability and reduce reporting burden on operators.

While better methane reporting is critical for investors, such improvement should also help operators. The process of measuring and reporting methane emissions will drive increased management attention to this issue, leading to waste reduction, higher revenues and improved positioning to comply with regulations. Furthermore, given the continued public concerns about the environmental impacts of fossil fuel development, improved transparency on methane management can foster constructive dialogue across multiple stakeholders and ultimately build trust for long-term operations.

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Introduction

Why This Report

In the course of Environmental Defense Fund's (EDF) work on methane science and policy, investors have expressed that they are increasingly focused on methane but are having trouble findingdata that would enable them to incorporate methane into their decision-making process. The data gap is problematic for two reasons. First, investors have hidden risks in their portfolios, ranging from reputational to regulatory to economic. For oil and gas investors, such risks cannot be eliminated through diversification,only appropriately managed. Second, investors cannot rigorously assess and compare company performance on methane without good information. Furthermore, without methane data, investors cannot engage in data-driven discussions with their portfolio companies that would foster greater attention to this issue and possibly prompt a proactive operational response.

EDF systematically analyzed how companies are reporting, in order to understand whether investors are getting the information necessary to assess how a particular company is managing this problem.

This report presents results from an analysis of the current state of corporate reporting of methane emissions and their related risks. The report discusses both the level and quality of reporting. There are various reporting venues for methane emissions and other ESG issues, intended for different audiences such as regulators, investors, customers and executives. For example, while EPA's Greenhouse Gas Reporting Program (GHGRP), a compliance reporting program, has substantial and detailed information on methane emissions for U.S. facilities, there are several limitations to the program which hinder its usefulness for investors.[7] This paper focuses on high-level, consolidated corporate disclosure with investors as the primary audience.

We reviewed, when available, CDP disclosures, sustainability reports, 10-Ks, and websites for 65 of the largest upstream and midstream companies with significant operations in the U.S. The analysis reviewed publically available data and used the most recent data available, primarily from 2014. The analysis investigated whether companies are reporting methane emissions and other related data, such as reduction targets and emissions reduction practices, that would signal to investors how well methane risks are being addressed operationally.

In addition to the analysis, this report makes recommendations to improve the state of methane reporting, including a set of four methane metrics that, if implemented, would bring a level of standardization and rigor that is currently lacking across the industry.

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Why Methane Matters

Methane is one of the most potent greenhouse gases —84 times more powerful than carbon dioxide in the first20 years after it is released. The U.S. oil and gas sector is the largest industrial source of methane pollution in the US — emitting more than 7 million metric tons of methane emissions each year.[8] That equates to the short-term climate impact of 160 coal-firedpower plants and enough lost natural gas to meet the cooking and heating needs of over 5 million American homes each year.

Data from reports prepared by leading climate scientists from the Intergovernmental Panel on Climate Change (IPCC) suggest that nearly a quarter of the warming we are experiencing today is caused by methane and other short term climate pollutants.[9] Because of varying timing of impacts for methane and carbon dioxide, reducing both is critical to comprehensively addressing climate change.

Addressing both methane and carbon dioxide is essential to any comprehensive response to climate change.

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Along with methane emissions, oil and gas operations also emit other pollutants, including smog-forming volatile organic compounds (VOCs) and cancer-causing pollutants like benzene. Reducing methane emissions will also deliver significantpublic health benefitsby cutting smog and hazardous air pollutants in our communities.

Methane is not just a climate issue or solely a U.S. problem. Because methane is the primary component of natural gas, methane emissions represent the loss of a saleable product. Recent analysis by the Rhodium Group found that in 2012, about 3.5 trillion cubic feet (TCF) of unburned natural gas, worth about $30 billion, was emitted globally from the oil and gas industry as a result of leaks and vented (i.e. intentional) emissions.[10] That loss is about the amount of gas brought to market in 2012 by Norway, the seventh largest gas producer.

Low-Cost Solutions Are Available

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A 2014 report by the consulting firm ICF International found that a 40% reduction in methane emissions by 2018 is achievable using currently available technology and would cost the industry as a whole roughly $2 billion in upfront capital costs and $108 million a year in operational expenditures —roughly a penny per thousand cubic feet of gas produced on average, system wide, in the U.S.[11] Approximately half of the reductions identifiedin the report come with a positive pay back for companies, since the value of the saved natural gas more than offsets the costs of the reductions. A similar report looking at Canada's oil and gas industry found even greater potential to reduce methane cost-effectively.[12]

Growing Investor Interest in Methane Emissions

There has been a notable uptick in activity and attention from oil and gas investors on the methane issue in the past few years. From 2014-2016, 15 methane-focused shareholder resolutions were presented to oil and gas companies, including Hess, Kinder Morgan and Occidental, to reduce emissions and provide better disclosure. Additionally, dozens of investors participated in webinars, lunches, and other discussions focused on methane in 2015, hosted by organizations such as Ceres.

In July 2015, a group of investors with $1.5 trillion in assets under management (AUM), including CalPERS, CalSTRS and BMO Global, signed a letter urging the U.S. government to institute standards to limit methane emissions from the oil and gas industry.[13] This letter represents over a four-fold growth in interest in terms of AUM compared to a similar investor letter released less than a year prior.[14] In September 2015, over 35 faith-based investors called on oil and gas companies to support the proposed EPA methane rules.[15] These investors acknowledge the long-term threat that methane emissions pose to the industry and the increase in investor confidence that would come through meaningful federal action to put in place rules to limit emissions.

Methane in the Context of ESG Reporting

Investors are increasingly using environmental, social and governance (ESG) data to identify trends and opportunities across sectors and ultimately make investment decisions. Incorporating such information can provide investors with a more holistic view of the companies they are analyzing, which not only enables more effective risk management but, as some evidence suggests, can also drive improved returns.[16] Such practices date back to the 1980s,[17] and the number of institutional investors asking for this information has grown over the last decade, with organizations such as the United Nations-supported Principles for Responsible Investment (UNPRI) Initiative,[18] CDP[19] and Ceres building networks of investors interested in incorporating such data. In a sign of the growing acceptance of utilizing such data, in October 2015, the U.S. Department of Labor reversed its prior stance on ESG issues, declaring that it is within an investment manager's fiduciaryduty to consider ESG issues in investment decisions.[20]

Incorporating methane emissions data into investment decisions would fitsquarely within the growing trend of considering ESG data alongside traditional financialdata.

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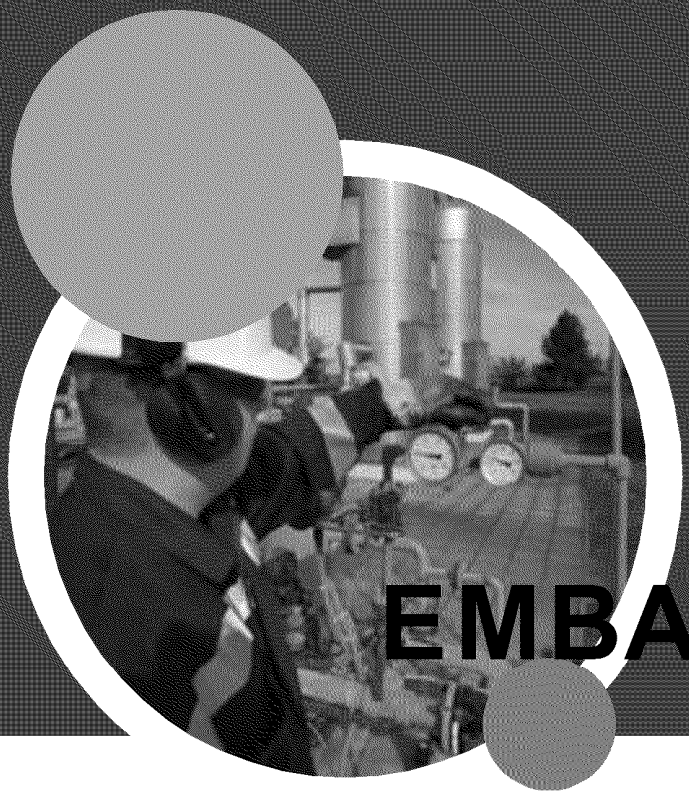
Need for Transparency



Increasing awareness and scrutiny on methane emissions increases risks for investors, necessitating better data to manage risk and assess performance. Companies would also benefitfrom increasing transparency.

- **Economic Risk: Poor disclosure hinders investor understanding of the amount of saleable product being wasted.**
- **Regulatory Risk: Current and future regulations to minimize emissions have potential financial and operational impacts.**
- **Reputational Risk: Methane emissions threaten natural gas' legitimacy in the transition to a cleaner energy economy, potentially jeopardizing "social license to operate," and limiting demand.**

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Methane emissions present numerous near and long-term risks for investors, the most important of which are discussed in detail below. Investors need sufficientdata to properly evaluate these risks and assets company performance.

Economic Risks of Methane Emissions

Methane released into the atmosphere never reaches the market, representing a potential loss of product and revenue, while simultaneously contributing to climate change. Methane emissions from the oil and gas industry represented $30 billion in wasted resources worldwide in 2012, with roughly $2 billion in the U.S. alone, which suggests there is a substantial financial opportunity for companies that properly identify and manage their methane emissions.[21] A 2014 ICF International study shows that cost-effective technologies and practices exist for companies to capture methane, and in certain cases even generate positive returns.[22]

Quality reporting and maagement of critical ESG factors such as methane are considered proxies for a well-run operation.[23] Given that methane is a saleable product, emission rates could be thought of as a measure of operational inefficiency.What gets measured gets managed, which can lead to improved company performance on an issue, mitigating financialrisks or providing opportunities. Investors need to understand where and how a company may be operating inefficiently,its implication for the top and bottom line, and how a company is addressing the resulting costs. As a result, companies should be able and willing to measure and report their methane leak rate. Companies that fail to disclose should face additional scrutiny.

Quality reporting and management of critical ESG factors such as methane are **considered proxies for a well-run operation.**

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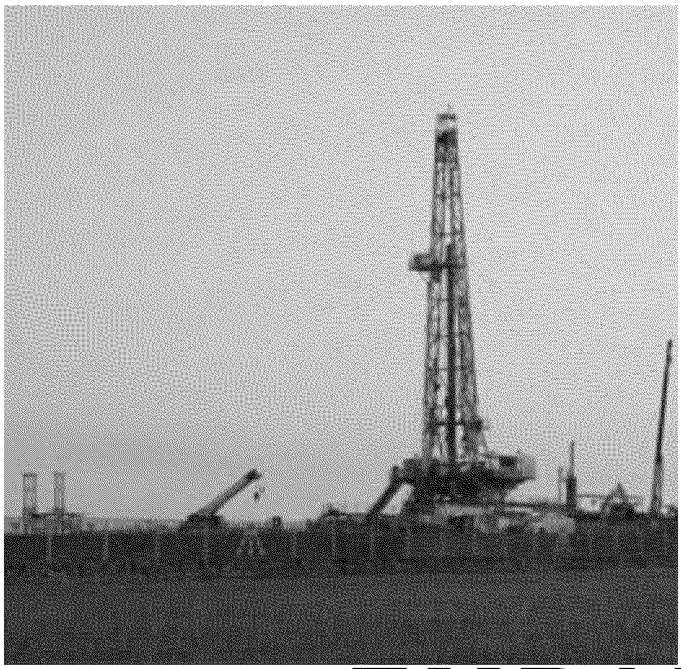

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Economic risk today includes the lost revenue or potential profit from methane emissions, as well as the broader implications on operational efficiency. It does not take into account the potential societal impacts of these emissions. However, if jurisdictions began attaching a price to methane pollution similar to carbon pricing schemes, the economic impact of these emissions could be far higher. As far as we know, no companies currently have an internal shadow methane price to account for the costs of the externalities of their emissions.

A point often lost in the discussion of economic interests is that the motivations of senior oil and gas company management are not always aligned with the interests of long-term shareholders. Senior management, driven by short-term compensation structures and quarterly reporting demands, may be motivated to cut corners to achieve short-term gain. But that can put a company's long-term economic performance at risk. For institutional investors that are either passive investors and/or take a buy and hold approach, methane emissions management, and the associated reporting around it, presents an important issue where investors may need to engage with management in order to protect their investment in the company. Such engagement will be more productive when investors have useful and rigorous data.

Regulatory Risks of Methane Emissions

As the methane regulatory landscape changes, investors should know how companies are positioned to respond. Companies that have clear data on emissions and disclose efforts and goals for reduction can signal to investors that they are prepared to manage compliance with forthcoming rules.

At the federal level, the EPA proposed methane emissions standards for new and modifiedoil and gas facilities in August 2015 that are expected to be finalizedin mid-2016. Likewise, the Bureau of Land Management (BLM) is soon expected to propose standards to reduce waste of natural gas produced on federal lands. These rules are part of a national strategy, announced by the White House in January 2015, to reduce U.S. methane emissions from the oil and gas sector to 40-45% below 2012 levels by the year 2025. Future regulations will likely address methane emissions from existing sources, which are generally not covered under the draft rules announced in August of 2015. In context, roughly 90% of emissions in 2018 are forecast to come from existing sources.[24] As such, these additional rules will be necessary to achieve the nationwide goal of reducing emissions 40-45%.

In addition to recently announced federal rules, state methane regulations already exist in some jurisdictions. In 2014, Colorado became the firststate to directly regulate methane from oil and natural gas operations.[25] Wyoming requires mandatory leak detection and repair to reduce pollution from oil and gas wells in in the Upper Green River Basin area, which has faced deteriorating air quality.[26] Ohio has rules that limit air emissions, and California and Pennsylvania are developing methane rules.

Companies that have clear data on emissions, and disclose efforts and goals for reduction, can signal to investors that they are **prepared to manage forthcoming rules.**

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Reputational Risks of Methane

Methane emissions threaten a core plank of natural gas's often touted value proposition – its ability to deliver a cleaner form of traditional energy.

Natural gas emits less carbon dioxide and conventional pollutants than coal when burned. Some investors have invested in natural gas, in part, because they see greater societal adoption of gas for these climate benefit reasons. However, every ton of methane emitted into the atmosphere compounds natural gas's climate footprint and reduces its contribution to a lower-carbon economy. Many people, including investors, who initially supported natural gas as a transition fuel to a lower carbon energy mix, are starting to question its role due to methane emissions.[27]

Without good data on methane emissions, investors cannot understand if the industry is minimizing emissions in an effort to produce the cleanest product possible, solidify the role of gas, and manage reputational risk.

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Every ton of methane emitted into the atmosphere **reduces natural gas' contribution to a lower-carbon economy.**

Operators Benefitfrom Improved Disclosure

Although this report centers on the benefits that improved methane disclosure provides to investors, the industry itself can benefit by reporting on methane. The International Petroleum Industry Environmental Conservation Association (IPIECA) cites enhanced business value, improved operations, strengthened relationships, and enhanced trust and credibility as the benefits of robust sustainability reporting.[28]

Build Trust — Without the public's trust in the industry's ability to address environmental and public health concerns, the industry may see community and other stakeholder acceptance diminish, a potential erosion in social license to operate. Conversely, polls reveal that 82% of Americans think that improved transparency on climate change initiatives will increase trust in a company.[29]

A relevant recent example of improved environmental disclosure in the oil and gas industry is FracFocus.[30] Through this program, in response to growing concerns around water contamination, the industry increased disclosure on chemicals used in hydraulic fracturing operations. Industry regards this heightened disclosure as a helpful step toward improving its standing with the public, including neighbors of operations.

As concerns around methane grow, industry has a financial interest in proactively providing better information around a company's methane emissions and efforts to reduce them. In addition to benefitswith the general public, a recent analysis by Goldman Sachs shows that social license to operate issues, of which methane is one, must be resolved to unlock capital-intensive downstream investments that capitalize on the surge of natural gas in the North America.[31]

Improve Decision Making — Better disclosure equips management with decision-useful data upon which to act. Improved methane awareness and disclosure will enable management to benchmark against competitors and make informed investments to improve performance and cut product loss.

Get Ahead of Regulations — Companies already taking action on methane can use improved disclosure to demonstrate to investors and downstream stakeholders that they are well positioned to thrive in a methane regulated world.

Increase Business Value — On an individual company basis, disclosing emissions and information around company practices can help companies distinguish themselves from their peers to the public and investors. Companies with good performance on material sustainability issues have been shown to outperform companies with poor management of material sustainability issues.[32] SASB lists methane as part of its "greenhouse gas (GHG) emissions" disclosure topic that is likely to constitute material information for companies in the oil and gas industry.[33]

Disclosing emissions and information around company practices can **help companies distinguish themselves from their peers.**

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Current State of Disclosure

EDF analyzed the methane disclosure practices of 65 of the largest U.S. oil and gas companies, and found the overall state of disclosure to be lacking.

- **Few companies provide data on methane.**
- **Poor data quality hinders usefulness for investors.**
- **There is insufficient standardization of methane reporting methodologies and metrics for methane across reporting platforms.**

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EDF hired Greenpoint Innovation to analyze the current state of corporate disclosure on the issue of methane emissions in the oil and gas industry. Focusing on companies with operations in the United States, EDF identifieda sample of 40 of the largest upstream producer companies[34] and 25 large midstream companies.[35] A full listing is available in the appendix.[36]

Through an investor lens, the research team analyzed the publicly-available reporting of these companies on a number of investor-focused disclosure platforms to determine if they are providing a sufficientlevel of methane data for investors to incorporate related risks into their decision-making process.[37] In doing so, we reviewed companies' websites, sustainability reports[38,39], CDP disclosures, annual reports and SEC filings.[40] The bulk of the analysis was conducted in July and August 2015.

The primary goal of this research was to analyze the state of disclosure broadly in terms of what and how much data is being reported and whether or not the data is actionable. A secondary objective was to understand which reporting mediums were most utilized by companies to report on methane emissions and related content.

The analysis focuses on key areas of interest to investors, including the reporting of methane emissions data, the implementation of methane reduction targets, management policies and operational programs to reduce emissions such as leak detection and repair, and management views on methane regulations.

Key Insights and Takeaways:

- **Zero companies disclose reduction targets, and few report methane-related data** — The majority of companies are not reporting any methane-related data, and disclosing companies are providing few details about their emissions or efforts to reduce them. No company discloses a quantitative target for reducing emissions.
- **The quality of disclosure is low, limiting usefulness for decision-making** — Reported information tends to be qualitative, vague and non-standardized, which hinders its usefulness and comparability.
- **The lack of rigorous and standardized metrics hampers disclosure quality** — The level and quality of data lacks consistency across platforms, as there are no standardized metrics and methodologies concerning methane.

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Zero companies disclose reduction targets, and few report methane-related data.

- Zero companies report a quantitative, time-bound methane emissions reduction target.
- 28% of companies report methane emissions.
- 49% of companies report on their leak detection and repair (LDAR) programs.
- 8% of companies report their methane emissions policy position.

Methane Emissions — Less than a third of the companies (28%) reported their methane emissions as a methane-specificfigure(i.e., not as part of a total GHG CO_2e figure). An additional 23% included their methane emissions in overall Scope 1 GHG emissions, with no breakout of distinguishable methane-specif data, or referred to an external source (e.g., EPA, The Climate Registry, Wyoming Department of Environmental Quality, etc.).[41] Finally, 51% didn't report methane emissions at all. Because of the disparate impacts of methane versus carbon dioxide over time, and the fact that methane is both a pollutant and an economic product, breaking out these emissions separately is critical for data to be actionable for investors.

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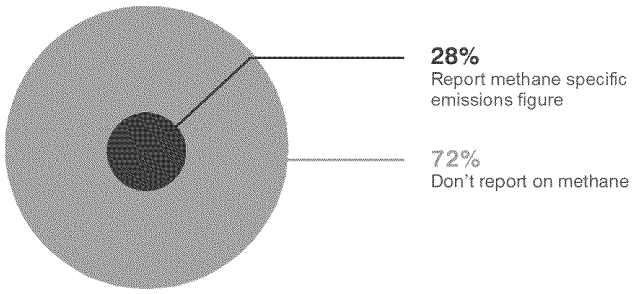
Reporting of Methane Emissions

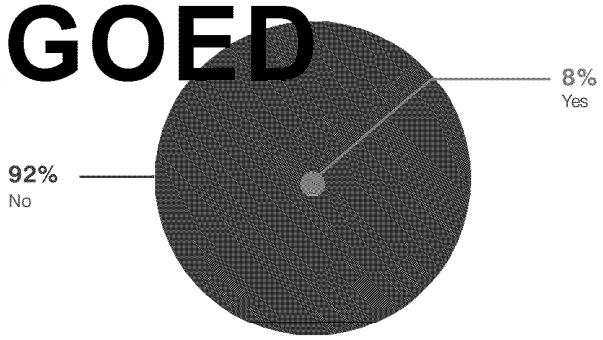


Reduction Targets — None of the 65 companies reported time-bound quantitative targets to reduce methane emissions from their operations. Targets are important for driving performance and creating a basis of accountability.[42] Targets help investors understand a company's long-term plans concerning methane, and their absence creates uncertainty over whether the issue is being appropriately managed.

Methane Reduction Operational Practices — 49% of companies reported conducting some form of leak detection and repair (LDAR). LDAR is the process by which companies locate and then repair leaks of methane, and is one of the most effective ways for a company to manage and reduce its emissions. As such, understanding how comprehensively a company conducts LDAR practices can help signify how well companies are addressing methane.

Methane Policy Position — Five of the 65 companies (8%) disclose their positions on policies to reduce emissions, or highlight their work with policymakers in crafting effective regulation. Corporate leadership on environment today requires engaging constructively on policy solutions. Disclosing a company's view on the role of regulations

Report Policy Positions



In its 2014 sustainability report, Anadarko discussed methane rules in Colorado and stated a commitment to "working with governmental agencies and other stakeholders in developing sound public policy that promotes appropriate and effective regulations, recognizing that oil and natural gas are essential to modern life and critical to the success of our economy."

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to address environmental issues like methane is a data point investors should consider as they are assessing how a company is managing methane and managing relationships with regulators that set rules in which businesses must operate. For example, Anadarko, Noble and Encana represented the industry in working with the Colorado state government, EDF and other key stakeholders to establish methane and volatile organic compound regulation in existing infrastructure, offering valuable data, input and leadership. Select companies hold dialogue with federal regulators, but corporate disclosure of the goals and nature of those dialogues is sparse.

The quality of disclosure is low, limiting usefulness for decision-making,

- 14% of companies report their methane emissions as a rate (e.g., emissions over production or throughput), a more effective way to assess and compare a company's emissions.
- 45% of companies report a qualitative ambition concerning methane emissions reductions, where they acknowledge the need for reductions, but provide no data around the amount of reductions sought or the timeline involved.
- Less than 2% of companies reported sufficientdata to provide comprehensive insight of their LDAR programs.

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In its sustainability report, Marathon Oil reports a methane emissions rate of 0.3%. This **allows investors to compare past and future figures against this benchmark,** tracking progress. It is also a useful figurewhen comparing Marathon to other companies.

Methane Emissions — While 28% of companies report their methane emissions, only 18% reported emissions as a rate, which is calculated by comparing a company's methane emissions to its production or throughput volumes. An emissions rate is a more effective way to assess a company's emissions than by absolute volume, as investors are better able to compare company performance despite differences in overall production level, and are better able to track progress over time.

Southwestern Energy is "Using FLIR cameras to survey facilities on a frequency of at least once per year, take direct measurements and identify fugitive emissions containing VOCs and methane and repair leaks as soon as practical. The LDAR program is being implemented across all of our operated areas within the company."

Qualitative reduction statements — While 35% of companies recognize in some way the desire to limit emissions, all of them do so through the use of vague, overly-qualitative terms. These qualitative statements do not include a quantitative reduction goal or a timeline to achieve it. Vague language limits the ability of investors to track progress, compare performance amongst companies and hold management accountable. Vague aspirations suggest an unstructured approach to the issue and could imply a lack of management attention to driving results.

Leak Detection and Repair — While 49% of companies mention conducting some form of LDAR, companies are not disclosing enough quantitative detail for investors to understand how comprehensive their LDAR program is in practice. There is minimal detail describing the methodology, geographic scope (percentage of assets covered) and frequency. Twenty-three companies provide some indication of geographic scope, and 18 companies provide information on the frequency of inspections. Only Southwestern Energy provided enough detail to reasonably convey the extent of its LDAR practices, stating the methodology, scope and frequency.

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Examples of vague, unspecificlanguage that makes up the entirety of a company's LDAR protocol description include, "our facilities are inspected regularly, using industry-standard leak-detection methods," and "monitoring wells are installed to watch for leaks." Further, while some companies provided information on assets covered by LDAR (e.g. regions, individual facilities, business segments, etc.), only Southwestern provides a percentage of assets to provide a sense of overall scope.

The lack of rigorous and standardized metrics hampers disclosure quality.

- No standardized methane metrics exist, making comparisons within and between platforms difficult.
- 22% of companies disclose methane related data in annual reports or mandatory SEC filings.
- Companies report on methane to a variety of voluntary platforms.
- Quality of reporting varies by platform, with websites providing the least usefulness.

When analyzing the reporting practices of companies across disclosure platforms, we found that a significant amount of companies are utilizing these platforms and reporting on ESG issues. Almost 40% provide a CDP questionnaire and nearly half produce a sustainability report. Since all of the companies analyzed were public, all have 10-Ks and websites. 94% of companies were reporting some ESG related information on their websites.

Of the voluntary platforms, 96% of companies have either a website, CDP response or sustainability report.

Furthermore, 22% of companies report relevant methane information in their 10-Ks or 20-F filings.Annual filingswith the United States Securities and Exchange Commission (SEC) are mandatory for companies listed on U.S. exchanges. Our analysis suggests that the SEC issued Interpretative Guidance from 2010 regarding company disclosure around climate change risks is not being adequately addressed in the context of methane.[46]

Although a notable number of companies are conducting some form of sustainability reporting, disclosure of quality information on methane remains limited. This disconnect suggests that reporting platforms need to improve their methodologies, ensuring that the most relevant questions are being asked and that the requests are aligned across platforms. One significantfactor contributing to the poor quality of methane data is the lack of rigorous, relevant and comparable methane metrics for investors.

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Corporate websites are the most ubiquitous example of methane reporting devoid of standardized guidance or methodology. After reviewing disclosure practices related to methane across a number of different platforms, we found that reporting was the least accessible on corporate websites. It was time-consuming to findmethane data on websites, as there is no standard placement from site to site. This is likely due to the lack of clear guidance or methodology regarding how companies should use their websites for ESG information. Given this, and the fact that established methodologies and platforms exist elsewhere, EDF's view is that leading disclosure practices should not include putting such information solely on the pages of companies' websites.

	CDP[43]	Sustainability Report	Website[44]	One of the Three
Publish	37%	45%	94%	92%
Include Relevant Methane Information[45]	29%	37%	40%	63%

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Secondary Findings

Large Companies Lead and Smaller Companies Lag, on Sustainability Reporting

While it is worth noting that this review only looked into 65 of the largest companies, we found a distinct difference in the level of transparency and quality of reporting between the largest and smallest companies, with larger companies in general providing more and better quality methane data. In an industry with thousands of companies smaller than the 65 within the scope of this analysis, the correlation between company size and quality of disclosure suggests that the overall state of methane disclosure for the industry beyond these 65 relatively large companies is very weak.

EDF recognizes the limited sample size of small-cap companies, but believes our findingsare generally consistent with other studies in showing that large companies tend to perform better around ESG disclosure. The 2014 CDP disclosure report cited in the CDP S&P 500 Climate Change Report 2014 states that companies "that rank in the top quartile versus industry group peers are more than 66% more valuable at $62.5 billion average market capitalization versus the S&P 500 average of $37.6 billion."[47]

U.S. Headquartered Companies Lag Behind Their Foreign Counterparts

As the focus of our analysis was on the largest producers and mid-stream oil and gas companies with operations in the U.S., the majority of companies featured in this study are based in the U.S. (58 of 65). Therefore, the resulting sample size may skew the results. However, our analysis did show that in general non-US oil and gas companies disclose on methane better than their U.S. peers. This pattern fits with the overall trend for sustainability reporting across all industries that other studies have found.[48]

All seven of the companies headquartered outside of the United States disclosed to CDP, compared to 27% of U.S.-headquartered companies.[49] 57% of the non-U.S. companies completed the supplementary CDP oil and gas sector module while only 20% of U.S. companies did the same. Further, all companies not headquartered in the United States produced sustainability reports and reported sustainability information on their websites, while 34% of U.S. companies produced a sustainability report, and 31% reported relevant information on their websites.

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	Disclose to CDP	Disclose to CDP OG Sector Supplement	Produce Sustainability Report	Post Sustainability Information on Websites
Large Cap	60%	43%	63%	51%
Mid Cap	11%	4%	26%	30%
Small Cap	0%	0%	0%	0%

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Why Are Companies Not Disclosing More?

The primary purpose of this analysis was to understand the current state of methane disclosure within the oil and gas industry. It was not within the scope of this analysis to document or analyze the factors driving disclosure practices within the industry, or lack thereof. However, we did interview a number of operators and investors following our analysis to hear their perspectives about why the current state of disclosure is so limited. While a number of reasons were cited as possible causes, the three below were the most-often mentioned:

- **Limited Bandwidth to Address Growing Reporting Requests —** As noted earlier in this paper, many companies cite "reporting fatigue" as a growing issue, with multiple organizations requesting data. Companies cited the lack of coordination among reporting organizations in terms of the format of data reported which adds to the delay. Given time and capital constraints, companies may not prioritize reporting on ESG issues like methane.
- **Lack of Pressure —** A number of investors suggested that companies were not getting enough pressure from stakeholders about providing data on methane. Without adequate pressure, management may calculate that the short-term costs of disclosure outweigh the potential benefits.
- **Compliance Reporting is Enough —** Companies cited the fact that they report some methane emissions data to the EPA as part of the Greenhouse Gas Reporting Program as alleviating the need to report on methane more broadly to investors.

Other reasons given for the lack of reporting were the relatively new focus from investors and reporting platforms on industry-specific issues such as methane, whereas in the past ESG reporting was focused on broader issues like water or supply chain risk. Some companies did not see the value in reporting. They suggested that too much credit is given for disclosure instead of operational practices that actually drive environmental improvements. Lastly, one company offered that many production company executives do not recognize climate change as real, and therefore feel no need to report methane emissions or other environmental data.

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Metrics — Making Methane Data More Useful

The lack of standardized methane metrics limits data usability. A standardized set of quantitative and rigorous metrics will better enable investors to assess and compare company performance over time and manage risk.

EDF proposes the following four metrics for adoption by platforms and companies:

- **Methane emission rate — the volume of methane emissions expressed as a percentage of gas production or throughput.**
- **Methane emission reduction targets — the amount and timeline of intended emissions reductions.**
- **LDAR protocol — the methodology, scope and frequency of a company's LDAR program allows investors to ensure that best practices are being utilized.**
- **Economic value of methane emissions — the economic value of a company's lost methane.**

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The oil and gas industry as a whole is doing a poor job disclosing meaningful information on methane emissions. While one part of the problem is simply the limited number of companies disclosing data, the other major issue is the quality of existing disclosures. A key deficiency is that reporting is overly reliant on qualitative information and boilerplate language, with not nearly enough company-specific quantitative data. These issues hinder users from comparing company performance over time and across companies.

Investors need rigorous, accurate and comparable information to properly assess and rank the performance of companies. Investors accomplish this in large part by looking at financial metrics such as earnings per share (EPS), year over year (Y/Y) sales growth and profit margins, which serve as proxies to understand how well management is running a company. No such methane metrics currently exist for methane emissions. The Economist Intelligence Unit, in a report on the financial risks to investors from climate change, acknowledged this issue, stating:

> *"Accurate information is important for all companies, but particularly vital for fossil-fuel businesses and large energy consumers…Unfortunately,* ***there is no standardized set of metrics or indicators for the disclosure of climate change-related information****…The fact that information on carbon emissions and climate risks is not readily available in a comparable form* ***limits the ability of institutional investors to manage the risks within their own portfolios effectively.****"*[50] *(Emphasis added by EDF)*

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With the goal of making data more rigorous, comparable and actionable, we have selected four methane metrics that we strongly encourage companies and reporting frameworks to adopt and begin reporting. While no small set of metrics can provide users with a complete picture, these metrics will give helpful information on how companies are handling the methane issue from a business and operational perspective. These metrics were selected with input from investors and operators, aiming to provide data on the most critical elements related to methane release, methane emissions rate, LDAR, target setting and economic waste.[51] The methodologies for calculating and presenting these metrics can be found in the appendix.

Methane Emissions Rates

Description — The amount of methane emitted by a company represented as an intensity factor. In this case, as a percentage of either production or throughput, depending on which segment of the supply chain a company is operating in.

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Why It's Important— The latest scientificstudies on methane emissions from the natural gas and oil industries suggest that, in order to maximize the climate benefitsof a transition from both diesel and coal to natural gas on all time scales, methane emissions from the industry must be limited to an emissions rate of 0.8%.[52] This means that each individual segment throughout the natural gas value chain, from well site to burner tip, must contribute much less than 0.8%. A study by the University of Texas found that the average rate associated with natural gas extraction is 0.42%.

An emissions rate provides a way to track individual company performance over time. Investors can quickly track emissions performance regardless of changes in production and assets.

Benefits— By framing emissions as a rate, the data becomes much more useful for fostering comparisons in two important ways. First, users can compare emissions performance across companies, regardless of company size, production volumes and geographic footprint of operations. Such comparisons would be difficult,if not impossible, to make with absolute emissions.

Second, an emissions rate provides a way to track individual company performance over time. Investors can quickly track emissions performance regardless of changes in production and assets.

Reduction Targets

Description— Targets for methane emission reductions and progress made against previous goals along pre-set timelines. For example, a production company with a starting methane emissions rate of 0.4% of gross production could choose a target of reducing emissions by 25% to reach 0.3% rate over 3 years.[53]

Why It's Important— Investors regularly receive guidance from companies about future financialand operational performance. This information is important to indicate the prospects for the company, but also to signal to investors that management is properly focused on important issues and fostering a culture of continuous improvement. For these same reasons, target setting should extend to sustainability issues like methane emissions. A lack of a reduction target could indicate that a company is not focusing on reducing product loss.

Benefits— Companies that proactively take emission reduction targets and implement best practices will be better positioned to thrive in a methane-regulated world. Investors could also engage with management on progress in achieving targets, discussing successes and failures and implementing necessary changes. As goals are set and benchmarked against others in the industry, progress can be accurately measured.

Several companies in the industry, including ONEOK and Shell, have already proactively taken the step of establishing targets to reduce flaringof excess gas. This is valuable and should be extended from flaringto methane emissions, which is a much larger contributor to warming in the next two decades. ONE Future, led by Southwestern

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Energy, has already started to do this through a voluntary methane emissions program in which companies set targets to bring system-wide emissions to less than 1% of production. While voluntary programs are not a substitute for regulatory safeguards, they can help participating companies demonstrate reduction potential, accelerate progress and receive recognition.

In its 2014 sustainability report, Shell set a specifictarget with a timeline for flaringreduction, stating they plan "to end continuous flaring by 2030." Companies, by reporting specificgoals with timelines for methane emission reduction, can **aid investors in assessing the future performance of companies, and their commitment to the methane issue.**

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Leak Detection and Repair Protocol

Description — The frequency, methodology, and scope (percentage of assets covered) of a company's leak detection and repair program (LDAR). LDAR is the process of locating and repairing methane leaks, otherwise known as fugitive emissions, which may occur throughout the oil and gas value chain and arise from operator errors and equipment failures. Frequency refers to how often a company observes its assets for leaks (e.g. monthly, quarterly, annually). Methodology is the process (e.g. optimal gas imaging (OGI) cameras, handheld sniffers, etc.) that the company uses to detect methane leaks, while scope is the percentage of the company's assets that are inspected under an LDAR program. According to the EPA, an LDAR program using OGI cameras quarterly can reduce methane and VOC emissions by 80%, compared to 60% semi-annually and 40% annually.[54]

Why It's Important— Fugitive emissions are one of the biggest sources of methane emissions throughout the supply chain. A findingfrom the Barnett Coordinated Campaign methane measurement science study shows that at any given time roughly 15% of production sites that were inspected were functional "super-emitters," responsible for 75% of the total methane emissions measured from those sites.[55] A small number of sources were responsible for the majority of emissions.

Higher emissions from these sites are often a result of avoidable operating conditions such as equipment leaks and tank venting that are relatively easy to fixwith frequent monitoring and repair practices.[56]

Finding and fixingleaks is a key component to any methane reduction program. An ICF study found that LDAR is the single biggest opportunity for methane emission reductions, with over a third of the reduction opportunities identifiedin the study coming from quarterly LDAR. [57]

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Benefits— Understanding how a company is implementing LDAR can be a good proxy of how seriously it is addressing methane emissions in its operations. The following three elements of a company's LDAR program will shape how effective it is at finding and fixing leaks to reduce emissions:

- Frequency of Inspections — The more often equipment is checked for leaks, the quicker leaks will be found and the more reductions a company can expect to achieve. Generally, monthly or quarterly inspections are considered best in class.
- Methodology — The employed methodology can also affect reductions. For example, LDAR using OGI camera technology that enables users to see otherwise invisible emissions will get more reductions than inspections done by olfactory, visual and audio (OVA) inspections alone, in which fieldpersonnel look and listen for leaks.
- Coverage — The coverage of a company's LDAR program will drive the level of potential reductions. The more assets covered, the more opportunities for emissions reductions.

Economic Value of Emissions

Description— The dollar value of methane emissions.

Why It's important— Methane is not just a pollutant, but also a product, since it is the primary constituent of natural gas. Estimates suggest that as much as $30 billion of methane is lost each year globally, with $2 billion wasted annually in the U.S. alone. This simple data point will quickly allow investors to understand the effects of annual methane emissions on a company's top line, particularly for upstream companies.

Benefits— This metric will enable investors to understand how efficientlya company is managing one of its main products and engage in a data-driven discussion around the economics of reducing emissions.

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Accuracy — Improving Methane Emissions Data

Compliance reporting of methane emissions provides a good foundation for a company's emissions inventory, but requires certain modifications in order to improve the data for investors. Three guiding principles should be followed to help bridge the gap and improve the overall accuracy of emissions data:

- **Measurement should be comprehensive, including all significant sources of emissions.**
- **Companies should employ frequent observation of operations as they gather data. This is particularly true of fugitive emissions sources, which by nature are difficultto predict in terms of timing and size of leaks.**
- **Companies should use rigorous quantification where possible, including greater utilization of direct measurement instead of emissions estimates.**

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Actual emissions from individual facilities in the transmission and storage segments were **260% higher than the emissions reported in Subpart W.**

Companies build inventories of methane emissions using a combination of direct measurement and estimates. For companies operating in the U.S., the EPA's Greenhouse Gas Reporting Program related to oil and gas systems, referred to as Subpart W, provides requirements on measurement methodologies. Unfortunately, Subpart W requirements have some limitations that could be addressed to strengthen the accuracy of data.

As outlined in the following table, the Subpart W program is not comprehensive in two ways: 1) only U.S. facilities of a certain size report emissions and 2) certain segments of the natural gas value chain are excluded from the program, as are some significantand known sources of emissions. In addition, the data relies on estimates of emissions rather than requiring direct measurement, resulting in potential failure to account for large fugitive leaks known as "super-emitters."

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For example, a study published in *Environmental Science and Technology* found that actual emissions from individual facilities in the transmission and storage segments were 260% higher than the emissions reported in Subpart W, as the program excludes monitoring in certain operating modes and of certain devices, such as reciprocating compressors in stand-by mode.[58]

Companies should address these limitations when creating a more complete and accurate data set for investors who will want to understand a company's entire emissions, not just those from U.S. assets or facilities of a certain size.

	Subpart W	Investor-focused ESG Platforms
Primary Audience	Regulators, scientists	Investors
Secondary Audiences	Oil and gas customers	Natural gas customers, the public, regulators
Scope — Sources	• Excludes facilities emitting below 25,000 metric tons / year CO_2e • Excludes certain emission sources such as onshore production blowdowns, reciprocating compressor rod packing vents in non-operating mode, and centrifugal compressor dry seal vents	• Includes all facilities regardless of size • Includes all emission sources
Scope — Geography	U.S. operations only	Global operations
Primary Reporting Focus	Facility-level emissions	Company-level emissions
Measurement Methodology	• Set by EPA • Primarily estimates emissions and activity factors with limited direct measurement	• Flexible • Opportunity for operators to do more direct measurement • Opportunity to update emissions estimates with latest data from methane measurement studies

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Finally, we offer recommendations that companies can follow to improve the accuracy of their emissions, building on the measurements required for Subpart W:

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- **Comprehensive —** Measurement should include all significantsources of emission. There are a number of emission excluded sources under Subpart W that should be included:
  - Onshore production blowdowns,
  - Reciprocating compressor rod packing vents in non-operating mode,
  - Centrifugal compressor dry seal vents and
  - Processing sector tanks.
- **Frequent Observation —** Because fugitive emissions are random by nature, and thus hard to predict in terms of timing and magnitude, companies should employ frequent (e.g., monthly or quarterly) observation of their assets in order to more accurately gauge the size of their fugitive emissions.
- **Rigorous Quantification—** While estimates of emissions and activity factors may be fairly accurate for certain sources, direct measurement can improve accuracy of emission for the following:
  - Fugitive Emissions — Currently, companies only need to use estimates for known leaks of methane, despite wide ranges of emission sizes. There is no requirement to quantify fugitive leaks. Companies should use robust detection and direct measurement of fugitive emissions sources in order to provide for a more accurate emissions database. Estimates do not capture the presence of super-emitters, the small percentage of sites that are responsible for large percentage of emissions.
  - Compressor Emissions — In the gathering and boosting segment, operators are allowed to estimate emissions from compressors, despite this being a significant source of emissions.

Subpart W measurement guidance **should evolve to better meet the needs of investors** and others for accurate and company-wide emissions data.

Additionally, best practice would suggest companies have their emissions figuresaudited, raising both the accuracy of the data and the level of trust from users. Platforms like CDP encourage verificationthrough their scoring methodology.[59]

Subpart W measurement guidance should evolve to better meet the needs of investors and others for accurate and company-wide emissions data, thus negating the need for companies to utilize different measurement methodologies for different audiences. Such alignment between more compliance-focused reporting via Subpart W and investor-focused reporting via the platforms discussed in this paper will reduce the reporting burdens on companies.

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Platforms — Reporting to the Right Places

There are a number of leading reporting organizations focused on improving corporate ESG disclosure. Some within the oil and gas industry already follow their guidance, and it is not EDF's intention to compete with or duplicate their work. However, organizations that adopt standardized metrics would increase the quality and rigor of the methane component of their platforms.

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Recognizing the leading work of many existing disclosure platforms, and the dangers of "reporting fatigue," it is not EDF's intention to duplicate the work of organizations already striving to put good, useful data into the hands of investors. Instead, EDF would like to highlight these organizations, identify how they can improve methane disclosure and encourage companies to use these platforms to disclose their methane emissions.

CDP

CDP is an international non-governmental organization (NGO) with the mission of providing a platform for companies to disclose climate and natural resource-related information for customers, shareholders and governments to access. Companies from over 80 countries disclose annual reports to CDP, making it "the largest and most comprehensive collection globally of primary corporate climate change, water and forest risk information."[60] CDP investor initiatives — backed in 2015 by more than 822 institutional investors representing an over US$95 trillion in assets — give investors access to a global source of year-on-year information that supports long-term objective analysis.

CDP's questionnaires touch on how a company's operations interact with climate, water, forests and cities. Thousands of global companies are asked, for example, to report on topics ranging from water use and supply chain traceability to CO_2 emissions. CDP also has sector supplements for some industries, including oil and gas. The oil and gas sector supplement has a number of methane specific questions related to emissions sources and activities to reduce emissions.

EDF engaged with CDP to streamline the methane subsection of the oil and gas questionnaire to feature the metrics proposed in this report, as well as information on the accuracy of emissions data. CDP has adopted EDF's recommendations and will be incorporating them into their 2016 questionnaire.

SASB

The Sustainability Accounting Standards Board (SASB) issues standards for companies to integrate non-financial, ESG data into their mandatory annual filingsto the SEC. SASB creates these standards through the lens of materiality, focusing their work on only the most financially-relevant environmental, social and governance issues for each industry.[61] Through their accounting standards, SASB seeks standardized accounting metrics that represent sustainability topics that are likely to constitute material information, ensuring alignment of reporting methodologies across public companies that adopt these standards.[62]

SASB identifiedGHG emissions, including methane, as a disclosure topic for oil and gas companies, due to its

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economic impact and stakeholder interest. In 2014, SASB released its provisional accounting standards for industries in the non-renewable resources sector. In standards for the oil and gas exploration and production industry, SASB wrote that "the management of highly potent methane emissions from oil and gas [extraction and processing] systems has emerged as a *major operational, reputational and regulatory risk for companies.*"[63]

For producers and midstream companies, SASB recommends quantitative reporting of consolidated GHG emissions in carbon dioxide equivalent metric tons, as well as percentage breakouts by individual hydrocarbon resource types (i.e. including conventional and unconventional oil and gas) and operational source (i.e. flaring,fugitive emissions). SASB metrics also incorporate the reporting of emissions reduction targets and reporting program against those targets.

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> "The management of highly potent methane emissions from oil and gas E&P systems has emerged as a **major operational, reputational and regulatory risk for companies" — SASB**

EDF encourages SASB to add a methane emissions rate to their standards. Additionally, SASB should also request companies to report emissions of methane separately from other GHGs, for both reporting of GHG absolute emissions and for emissions reductions target setting.

SASB recognizes the importance of companies reporting their strategy for managing and reducing Scope 1 emissions including methane, which they highlight in their Oil & Gas Exploration & Production Sustainability Accounting Standard.[64] Because it is the biggest opportunity to reduce methane emissions, SASB should encourage companies to discuss their use of LDAR in the context of reducing methane emissions (as distinct from other Scope 1 emissions) utilizing EDF's LDAR metric so that companies do so in a way that enables investors and others to gauge the effectiveness of their LDAR practices.

In 2016, SASB will be doing a review of their provisional standards in deep consultation with industry players, including oil and gas, and will take our recommendations under review for potential incorporation.

GRI

GRI is an international organization that helps businesses, governments and other organizations understand and communicate the impact of business on critical sustainability issues such as climate change, human rights, corruption and many others.

GRI provides a widely-used standard on sustainability reporting and disclosure. GRI's most recent Sustainability Reporting Standard, the G4, was released in 2013. GRI produced Oil and Gas Sector Disclosures that definesa set of standards specificallytailored for the industry. This reporting guidance was created through consultation of a working group composed of companies, investors, NGOs and research organizations in the industry. It covers a range of topics including GHG emissions, renewable energy research, risk assessment, impact on communities and emergency preparedness.

GRI's current G4 Standard asks for general information on GHG emissions, rates and targets. However, the Standard does this in carbon dioxide equivalent units and does not offer a specificcalculation methodology, allowing companies to calculate these figuresas they choose. EDF has engaged with GRI to update their framework to include emissions rates, LDAR and economic value, as definedin the Metrics section of this report, in the oil and gas supplement moving forward. We have also engaged with GRI on disclosure of accuracy of data. Finally, we have encouraged GRI to use the 20-year and 100-year global warming potential (GWP) when calculating emissions in carbon dioxide-equivalent units.

In 2016, GRI will be doing an extensive public review of their Standards and seek recommendations from interested parties for potential incorporation of new contents.[65]

IPIECA

The International Petroleum Industry Environmental Conservation Association (IPIECA) is an international oil and gas industry association for environmental and social issues. With members accounting for over 60% of the world's oil and gas production, IPIECA focuses on a range

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of issues, including a commitment to improving the state of sustainability reporting within the industry. Similar to GRI, IPIECA publishes a framework for sustainability reports, specifically tailored to the industry, identifying key indicators for companies to address when preparing annual reports. The most recent guidance was published in September 2015.

Included in the guidance's environmental, social and governance indicators is a section with recommendations for the reporting of emissions. IPIECA calls for the reporting of direct methane emissions, either in terms of CO_2 equivalent or metric tons, and also suggests companies report emission intensities for all combined GHGs.

The guidance would benefit from changes to its indicators, insisting on the reporting of methane emissions separate from carbon dioxide. Similarly, IPIECA should request that companies report a stand-alone methane emissions rate. In addition, a call for the disclosure of emissions reductions targets, LDAR protocol, and economic value of emissions would improve sustainability reports.

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SEC Disclosure

The SEC stands apart from the above mentioned organizations in that it focuses primarily on financial reporting that is required for publically listed companies. Even so, the SEC can help get better ESG data in the hands of investors through their reporting rules. While voluntary reporting is valuable to investors, mandatory reporting is also critical given the relative focus investors give to reviewing 10-K filings as opposed to voluntary reports.

In 2010, the SEC issued interpretative guidance on climate disclosure describing how companies should report in their 10-Ks on the material risks presented by climate change to their assets.[66] The response to the SEC's guidance has been poor, with very few companies complying with the terms of the guidance. According to a report by Ceres, 41% of S&P 500 companies did not disclose climate related information in their 2013 10-K filings.[67] Those that did report something did so in a brief manner, using qualitative language that does not assist investors trying to analyze material issues. These findings are consistent with the analysis we have presented in this report.

While SEC's interpretative guidance covers all climate change risks and is thus much broader than just methane emissions, companies should report their methane

> While voluntary reporting is valuable to investors, **mandatory reporting is also critical** given the relative focus investors give to reviewing 10-K filings as opposed to voluntary reports

emissions as part of the discussion regarding what, if any, risk they may face from coming federal and state regulations. Incorporating the metrics we identified in their 10-K filings will help make these disclosures more actionable for investors. SASB's standards for reporting material environmental information can help companies effectively put critical information into their SEC filings.

Sustainability Reporting Evaluations and Performance Rankings

There are several groups that rank companies based on their disclosure around ESG issues. While these organizations are not reporting platforms, they play an important role is driving greater disclosure by shining a spotlight on disclosure practices and incentivizing companies to improve via ranking systems.

THE INVESTOR ENVIRONMENTAL HEALTH NETWORK

The Investor Environmental Health Network (IEHN) is a group of investment managers that have partnered with NGOs to drive companies to increase their environmental responsibility through dialogue and shareholder resolutions. IEHN is focused on improving disclosure by oil and natural gas companies, specifically around hydraulic fracturing. In 2015, IEHN released its updated "Disclosing the Facts" report, featuring a ranking of 30 companies and their practices concerning fracking risk disclosure.[68]

The report examines disclosure practices around toxic chemicals, water and waste management, community impacts and air emissions, including methane. Companies are ranked on a point system, receiving one point for each question they report against. Overall, IEHN's analysis

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yielded similar conclusions to our analysis, stating "too few companies are providing quantitative disclosures and far too many companies are leaving investors in the dark on far too many issues."

In past reports, when concerning methane, IEHN looked at disclosure practices touching upon methane leakage rates and some aspects of LDAR programs. More recently, IEHN strengthened the questions in the 2015 edition of its report to incorporate an intensity rate covering all methane emissions (both fugitive and vented), while also looking for disclosure around all three parts of our LDAR metric: frequency, methodology and coverage. IEHN has also added a question around whether companies report a methane emissions reduction target. Moving forward, oil and gas companies are now publically scored on how well they report against these metrics.

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Additional Organizations Focused on Ranking and Evaluations

Groups like Bloomberg, Dow Jones and MSCI have developed reports and ratings of companies based on ESG issues. For example, Bloomberg provides four disclosure scores on companies for environmental, social, governance and overall ESG transparency based on the percentage of Bloomberg ESG data points found in public disclosure. MSCI produces a Global Climate Index, identifying the 100 companies that lead in addressing the conditions that contribute to climate change. Similarly, the Dow Jones Sustainability Index (DJSI) evaluates the world's largest 2,500 publicly traded companies on relevant sustainability criteria.

When measuring the ESG performance of oil and gas companies, rating groups should ensure that methane is incorporated into their analyses. An oil and gas company's climate and environmental efforts cannot be accurately rated without a consideration of this issue.

Voluntary Industry Initiatives

While the following initiatives are not reporting platforms focused on providing ESG data for investors, they may provide some information on methane that is complimentary to the platforms mentioned previously. Overall, participation in these voluntary industry initiatives should be seen by investors as a commitment by companies to understand and reduce their emissions.

One Future Initiative

Members of ONE Future, an industry initiative including fiveof the companies analyzed in this report (Apache, BHP Billiton, Hess, Kinder Morgan and Southwestern Energy), are focused on improving methane management across the entire natural gas value change. One Future's stated goal is to reduce methane emissions across the entire value chain to less than 1% of total natural gas gross production.[69] Each segment of the value chain (e.g. production, transmission) will have its own emissions intensity target that each company within that segment must reach.[70]

The initiative asks companies to disclose individual emissions not only as a rate but also as emission intensity targets. Thus, One Future companies will have already committed to reporting on at least two of the EDF recommended methane metrics by 2017. This initiative is a positive step toward industry adoption of quantitative methane emissions reduction targets and improved reporting. One Future has been incorporated into the Environmental Protection Agency's "Methane Challenge" Program.

The measuring and reporting component of One Future will be more comprehensive than what companies provide in compliance reporting through Subpart W. Member companies, through the One Future reporting mechanism, will measure and disclose emissions for all sources by following standardized protocols.

Participation in these voluntary industry initiatives should be seen by investors as a **commitment by companies to understand and reduce their emissions**

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Oil and Gas Methane Partnership (OGMP)

While the OGMP is not a company-wide reporting initiative, investors may findsome value in the information disclosed through participating companies' effort to reduce their emissions.

The Partnership, created through consultation with industry, creates a global platform for companies to more fully understand and systematically manage their methane emissions. Recognizing the importance of reducing these emissions, seven companies (BG Group, ENI, PEMEX, PTT, Total, Statoil and Southwestern), key governments (France, UK and U.S.), and civil society (EDF) launched the OGMP in September 2014. The OGMP is designed to provide an international venue for participating companies to report on emissions from nine core sources thought to be the biggest sources of methane emissions. First, partner companies decide which of their operations to include in the reporting and then establish the viability of control options for emissions sources. Then, the companies implement those controls deemed to be feasible.

The Partnership was designed as a mechanism for interested companies not only to minimize emissions, but also to credibly show their leadership for doing so. As a result, the Partnership will enable companies to efficiently disclose information in order to recognize and demonstrate progress of individual companies.

While yet to be finalized, the level of reporting detail likely to come from OGMP will be important in developing better global data on oil and gas methane emissions. The highly source-specific detail may be a good complement to the investor-focused reporting platforms discussed above, which tend to focus more on consolidated, company-wide emissions.

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Conclusion

There is a stark but addressable disconnect between the outsized importance of methane as a climate and reputational risk and the scant disclosure it receives in today's corporate reporting practices. With public pressure rising on fossil fuel companies generally, and investor demands increasing for better climate risk disclosure, the time is ripe to improve methane disclosure on the path toward comprehensively addressing the issue. EDF recommends the following:

Metrics

The adoption of the following methane metrics as a centerpiece for methane reporting for relevant stakeholders:

1. **Methane emissions rate**
2. **Methane reduction target**
3. **LDAR protocol(s)**
4. **Economic value of emissions**

These metrics support quantitative, decision-useful information that stakeholders can utilize to compare companies against each other, as well as asses a single company's progress over time.

Accuracy

Companies should continually seek to improve the accuracy of emissions data, and incorporate a robust direct measurement program. Measurements should be comprehensive, frequently observed and rigorously quantified.

Platforms

Platforms should work to raise the prominence and quality of methane data in their disclosure methodologies. Adopting the recommended metrics will help accomplish this, while helping to streamline methane reporting thereby lessening the burden on operators.

Methane disclosure will only improve if all stakeholders engage on this issue. Investors should ask companies for further disclosure and then must use the available data in their investment process and discussions with management. Operators should utilize the investor-focused platforms discussed in this report, given the current data limitations of compliance reporting. Finally, disclosure platforms should streamline methane reporting using the proposed metrics in order to make data more actionable for investors while reducing reporting fatigue for operators.

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Appendix

Recommendations and Resources for Investors

Investors, as owners of oil and gas companies, are uniquely positioned to improve the current state of methane disclosure. To do so, EDF recommends investors take the following actions:

- **Ask management for better data –** One reason companies may not be disclosing more on methane is due to lack of pressure from investors. Ask companies to provide more and better information to enable you to better assess performance and manage risk. Note that Subpart W reporting is not sufficient.
- **Work with disclosure platforms –** Investors need to provide their expertise and voice to ensure organizations such as CDP, GRI, SASB and IPIECA are guiding companies to disclose relevant and useful data on methane. By urging disclosure platforms to adopt our metrics, you can help achieve this goal.

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Lastly, it is important for investors to not only ask for information, but also to use this data in both investment decisions and data-driven dialogue with company management. To help with the latter, the following is a list of questions that investors should consider asking of management.

OPERATIONS

- What is the scope, frequency, and methodology of your LDAR activities? What have you learned from LDAR activities currently underway and what is your plan to drive further reductions?
- If you have no methane targets, when will you set them? If you do, what are the barriers to achieving them and how will you overcome them?
- What is the value of your lost methane, and how do you plan on capturing that value and bringing it to the bottom line?
- How are you planning to meet anticipated federal standards to limit methane emissions?

MANAGEMENT

- What incentives are in place to motivate in-field personnel (corporate staff and contractors), senior management and other key internal stakeholders to reduce methane emissions?
- What training programs do you have in place for in-field personnel to prevent error-driven methane leaks?
- Who is the most senior executive responsible for your company's methane mitigation strategy?

POLICY AND STRATEGY

- Have you considered utilizing an internal shadow price on methane to better drive management attention and capital to reduction projects, similar to what some companies are already doing with internal carbon pricing?
- Is the company constructively participating in shaping cost-effective regulations of methane at the state or federal level in the US (or, if relevant, other countries of operation)?
- What factors were considered when determining your company's strategy to reduce emissions?

Metric Methodologies

Emission Rates: Companies should calculate their emissions rate in two slightly different ways: (1) a standard emission rate with methane emissions as a percent of total methane produced, and (2) an energy delivery efficiencyrate with methane emissions as a percent of energy production.

Both of these calculations allow investors to properly account for differences in the composition of production between companies. For example, a company that produces primarily oil might have a very high standard emission rate since their emissions at the well site (the numerator) could be comparable to gas-focused companies but the amount of gas they produce (the denominator) is relatively small. In these cases, the energy delivery efficiencyrate will more accurately reflectthe company's emissions performance.

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The standard emission rate is calculated by dividing methane emissions by methane production (for upstream operators) or throughput (for midstream companies). Companies should use average methane composition to determine methane production.

The energy delivery efficiencyrate is calculated by dividing methane emissions by energy production or throughput expressed in thousand cubic feet by converting oil to gas using the U.S. Geological Survey conversion of 6,000 cubic feet per barrel of oil.

Companies should provide all inputs (e.g., absolute emissions and production/throughput) that go into the calculations of both rates. Absolute emissions should be disclosed in units of methane. If units are converted to CO_2 equivalence, both the GWP over 100 and 20 years should be used.

Reduction Targets: Companies have discretion in selecting specifictargets that will work with the context of their culture and philosophy for environmental targeting. Companies can set targets based on either or both absolute emissions and emissions intensity. Either way, strong targets are quantitative, motivational, time-bound and transparent.

Leak Detection and Repair Protocol: Frequency and methodology do not require any calculations. Calculating coverage will vary depending on whether a company is a midstream or upstream company. For upstream companies, we definecoverage as percentage of well sites covered by LDAR. For midstream companies, coverage is definedin two separate ways: (1) percent of pipeline miles covered by LDAR; and (2) percent of facilities surveyed as defined by the EPA. Both of these numbers should be reported for midstream companies. If a company inspects assets with various frequency rates (e.g., quarterly in Colorado, annually in California), then it should seek to provide a breakdown by frequency, and the percentage of assets covered under each frequency bucket.

Economic Value of Emissions: Reporting Scope 1 methane emission figures for producers in terms of economic value can be done by multiplying the average sale price of gas (expressed as $/Mcf) by the total Mcf of gas production for the year. For midstream assets, a similar calculation can be done by multiplying the average natural gas price for the reporting year ($/Mcf), taken from sources such as Henry Hub, by the total throughput of natural gas.

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Summary of Company Data

The following is a high-level summary of the company-specificfindingsregarding methane disclosure practices. A more detailed dataset can be found on EDF's landing page for this report.

Company	Size	Report Methane Emissions as a Rate	Report Methane Emissions as a Standalone Figure	Report a Quantitative Standalone Figure	Report Position on Methane-Related Policy	Discuss LDAR Use
Anadarko	Large	✓	✗	✗	✓	✓
Antero Resources	Large	✗	✗	✗	✗	✗
Apache	Large	✓	✓	✗	✗	✓
BHP Billiton	Large	✗	✓	✗	✗	✓
Boardwalk Pipeline Partners	Medium	✗	✗	✗	✗	✗
BP	Large	✗	✓	✗	✗	✓
Buckeye Partners	Large	✗	✗	✗	✗	✓

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Company	Size	Report Methane Emissions as a Rate	Report Methane Emissions as a Standalone Figure	Report a Quantitative Standalone Figure	Report Position on Methane-Related Policy	Discuss LDAR Use
Cabot Oil & Gas	Large	✗	✗	✗	✗	✓
Chesapeake Energy	Medium	✗	✗	✗	✗	✓
Chevron	Large	✓	✓	✗	✗	✗
Cimarex Energy	Large	✗	✗	✗	✗	✗
Conoco Phillips	Large	✓	✓	✗	✗	✓
Consol Energy	Medium	✓	✓	✗	✗	✓
Continental Resources	Large	✗	✗	✗	✗	✗
Crestwood Equity Partners	Medium	✗	✗	✗	✗	✗
DCP Midstream Partners	Medium	✗	✗	✗	✗	✗
Devon Energy	Large	✗	✓	✗	✓	✗
Dominion Midstream Partners	Medium	✗	✗	✗	✗	✓
Enable Midstream Partners	Medium	✗	✗	✗	✗	✗
Enbridge	Large	✗	✓	✗	✗	✗
Encana	Large	✓	✗	✗	✗	✗
Energen	Medium	✗	✗	✗	✗	✗
Energy Transfer Partners	Large	✗	✗	✗	✗	✗
Enlink Midstream Partners	Medium	✗	✗	✗	✗	✓
Enterprise Products Partners	Large	✗	✗	✗	✗	✗
EOG Resources	Large	✓	✗	✗	✓	✓
EP Energy LLC	Medium	✗	✗	✗	✗	✗
EQT Midstream Partners	Medium	✗	✗	✗	✗	✗
EQT Resources	Large	✓	✗	✗	✗	✗

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Company	Size	Report Methane Emissions as a Rate	Report Methane Emissions as a Standalone Figure	Report a Quantitative Standalone Figure	Report Position on Methane-Related Policy	Discuss LDAR Use
Exco Resources	Small	✗	✗	✗	✗	✗
Exxon Mobil	Large	✓	✗	✗	✗	✓
Freeport-McMoRan Inc.	Large	✗	✓	✗	✗	✗
Hess Corp	Large	✗	✓	✗	✗	✗
Kinder Morgan	Large	✗	✗	✗	✗	✗
Linn Energy	Medium	✗	✗	✗	✗	✓
Magellan Midstream Partners	Large	✗	✗	✗	✗	✓
Marathon Oil	Large	✗	✓	✗	✗	✓
MarkWest Energy Partners	Large	✗	✗	✗	✗	✗
NewfieldExploration	Medium	✗	✗	✗	✗	✗
NiSource	Large	✗	✓	✗	✓	✓
Noble Energy, Inc.	Large	✗	✓	✗	✓	✓
Nu Star Energy	Medium	✗	✗	✗	✗	✗
Occidental	Large	✗	✓	✗	✗	✓
ONEOK	Medium	✗	✗	✗	✗	✓
Pioneer Natural Resources	Large	✗	✗	✗	✗	✗
Plains All American Pipeline	Large	✗	✗	✗	✗	✓
QEP Resources	Medium	✗	✗	✗	✗	✗
Range Resources	Medium	✓	✓	✗	✗	✓
Rice Energy	Medium	✗	✗	✗	✗	✗
Royal Dutch Shell plc	Large	✗	✓	✗	✗	✓

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Company	Size	Report Methane Emissions as a Rate	Report Methane Emissions as a Standalone Figure	Report a Quantitative Standalone Figure	Report Position on Methane-Related Policy	Discuss LDAR Use
SandRidge Energy	Small	✗	✗	✗	✗	✗
Seneca Resources (National Fuel)	Medium	✗	✗	✗	✗	✓
SM Energy Company	Medium	✗	✗	✗	✗	✗
Southwestern Energy Co	Medium	✗	✗	✗	✗	✓
Spectra Energy	Large	✗	✓	✗	✗	✓
Tallgrass Energy	Medium	✗	✗	✗	✗	✗
Targa Resources	Medium	✗	✗	✗	✗	✗
TC Pipelines	Medium	✗	✗	✗	✗	✗
The Williams Companies	Large	✗	✗	✗	✗	✓
Total S.A.	Large	✗	✓	✗	✗	✓
TransCanada	Large	✗	✗	✗	✗	✓
Ultra Petroleum	Medium	✗	✗	✗	✗	✓
Unit Corporation	Medium	✗	✗	✗	✗	✗
Western Gas Partners	Medium	✗	✗	✗	✗	✗
WPX Energy Inc.	Medium	✗	✗	✗	✗	✗

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Resources

Reporting and Disclosure Resources

CDP

CDP, formerly Carbon Disclosure Project, is an international, not-for-profitorganization providing the only global system for companies and cities to measure, disclose, manage and share vital environmental information. CDP works with market forces, including 822 institutional investors with assets of US$95 trillion, to motivate companies to disclose their impacts on the environment and natural resources and take action to reduce them.

www.cdp.net

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CDP INVESTOR ENGAGEMENT TOOL

Find out how to engage with company management that do not respond to CDP information requests.

www.cdp.net/Docs/investor/investor-engagement-tool.pdf

CERES

Ceres is a non-profitorganization advocating for sustainability leadership, mobilizing a network of investors, companies and public interest groups to accelerate and expand the adoption of sustainable business practices and economic solutions.

www.ceres.org/files/methane-emissions

Also refer to Ceres' report, done in partnership with BlackRock, about strategies for investor engagement around ESG issues: www.blackrock.com/corporate/en-us/literature/publication/blk-ceres-engagementguide2015.pdf

GLOBAL REPORTING INITIATIVE (GRI)

GRI is an international independent organization that helps businesses, governments and other organizations understand and communicate the impact of business on critical sustainability issues such as climate change, human rights, corruption and many others. GRI provides widely used standards on sustainability reporting and disclosure, enabling businesses, governments, civil society and citizens to make better decisions based on information that matters.

www.globalreporting.org

IPIECA

IPIECA is the global oil and gas industry association for environmental and social issues. IPIECA produces industry reporting guidelines for voluntary sustainability reporting.

www.ipieca.org

OIL AND GAS METHANE PARTNERSHIP

The Climate and Clean Air Coalition (CCAC) has created a voluntary initiative to reduce methane emissions in the oil and gas sector: the CCAC Oil & Gas Methane Partnership. The CCAC officiallylaunched the Partnership with founding companies at the UN Secretary General's Climate Summit in New York on September 23, 2014. The founding companies are: BG-Group, Eni, Pemex, PTT, Southwestern Energy, Total and Statoil.

www.unep.org/ccac/Initiatives/CCACOilGasInitiative/CCACOilGasMethanePartnership/tabid/794017/Default.aspx

THE SUSTAINABILITY ACCOUNTING STANDARDS BOARD (SASB)

The Sustainability Accounting Standards Board (SASB) is a non-profitthat develops and disseminates sustainability accounting standards that help public corporations disclose material, decision-useful information to investors. Their standards are developed through a process that includes evidence-based research and broad, balanced stakeholder participation

www.sasb.org

Also refer to SASB's Non-Renewable Resources standards:

www.sasb.org/sectors/non-renewable-resources/

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Background Information on Methane Science and Economics

EDF

For those interested in further information concerning the science behind methane emissions, EDF provides the following resources:

Methane background: www.edf.org/methane-other-important-greenhouse-gas

Measurement science studies on methane leakage: www.edf.org/energy/methaneleakage

ICF INTERNATIONAL

A management, technology and policy consulting firmthat focuses on a number of markets, including oil and gas. ICF has completed a series of studies looking at the economics of methane emission reductions from the oil and gas sector in the U.S., Canada and Mexico.

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U.S. Study: www.edf.org/energy/icf-methane-cost-curve-report

U.S. Federal and Tribal Lands Study: www.edf.org/energy/study-finds-substantial-loss-natural-gas-us-federal-and-tribal-lands

Canada Study: www.edf.org/climate/icf-report-canadas-oil-and-gas-methane-reduction-opportunity

Mexico Study: www.edf.org/energy/icf-report-mexicos-oil-and-gas-methane-reduction-opportunity

RHODIUM GROUP

Rhodium Group (RHG) combines policy experience, quantitative economic tools and on-the-ground research to analyze disruptive global trends. RGH supports the investment management, strategic planning and policy needs of clients in the financial,corporate, non-profitand government sectors. RHG produced a study, commissioned by EDF, looking at global methane emissions from the oil and gas industry.

www.rhg.com/reports/untapped-potential

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34. Also known as exploration and production companies, these companies focus on searching for oil and gas and bringing it to the surface through the drilling of wells.

35. Mostly pipeline companies, this sector focuses on the transportation, storage, and wholesale marketing of oil and gas

36. Of the 65 companies researched , 35 were large cap (greater than $10 billion market capitalization), 27 were mid cap ($2 - $10 billion market capitalization) and three were small cap ($300 million - $2 billion in market capitalization). Market capital size is accurate as of May 2015. Stock market values may have shifted since then.

37. For the purposes of this report, we consider "investor focused disclosure platforms" as annual reports, SEC filings,CDP disclosures, company websites and sustainability reports

38. Sustainability Reports as a category includes, but not limited to, company produced reports with a variety of titles, including "Corporate Sustainability", "Corporate Social Responsibility", "Corporate Responsibility" and "Corporate Citizenship"

39. The majority of sustainability reports are dated 2014 (19 of 29), six were 2013, 2 are 2013-2014 and two were 2015

40. SEC filingsinclude 10-K, 10-F and 20-F

41. Data reported to EPA's Subpart W is has limitations due to shortcomings in measurement methodology and scope (See Accuracy section for further details).

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44. Although all 65 companies publish a website, 6% do not contain any sustainability-related content, and thus are not considered here as "publishing through this sustainability reporting medium."es, this sector focuses on the transportation, storage, and wholesale marketing of oil and gas

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ENVIRONMENTAL ENERGY INSIGHTS

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EVs by the Numbers (Part 1)

Summary: Today there are more plug-in electric vehicle (PEV) models available from major auto manufacturers than there have ever been, and a growing number of PEVs on the road. Despite this, major challenges to greater PEV adoption remain, including high cost, limited range between charges, and lack of public charging infrastructure. Some utilities see PEVs as an opportunity, particularly in the face of growing distributed generation, but depending on how they are charged greater PEV penetration could also increase peak loads and require costly infrastructure upgrades. This article is the first in a series that will examine the potential effects of PEVs on electric utilities, starting with a summary of the current state of the U.S. PEV market, lessons learned about consumer charge behavior from PEV pilot programs, and lessons learned from utility pilot programs to test alternative PEV charging rates.

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State of the PEV Market

According to the Department of Energy, in 2009, there were only 57,185 electric vehicles registered in the U.S., which was less than 0.02 percent of light-duty cars and trucks then on the road. With the introduction of the battery electric (BEV) Nissan Leaf and the plug-in hybrid (PHEV) Chevy Volt in December 2010, PEV sales started to climb quickly. Since the introduction of these two vehicles, PEV sales in the U.S. have totaled 308,000 vehicles through March 2015, including over 123,000 sold in 2014 and 23,000 sold in the first three months of 2015. In the last two years, BEV sales have outpaced sales of PHEVs.

While a number of other models have since been introduced (see below), the Volt and Leaf have consistently been top sellers since their introduction, each accounting for approximately 22 percent of PEV sales since 2010, followed by the high-end BEV Tesla Model S (13.3 percent of sales) and the plug-in version of the popular Toyota Prius hybrid (13.2 percent of sales).

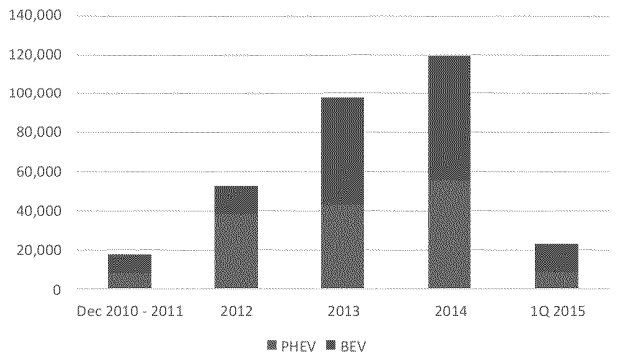
California is the largest market for PEVs, with approximately 44 percent of all U.S. PEV sales since 2010, almost equally split between PHEVs and BEVs. California also has one of the highest PEV penetration rates of any state, at more than three PEVs per 1,000 registered vehicles. Other states with higher than average PEV penetration rates include Washington, Oregon, Hawaii, Georgia, and Maryland.

However, despite dramatic gains in the last five years, PEVs still account for only about 0.7 percent of annual new light-duty vehicle sales, and less than 0.2 percent of all cars and light trucks on the road.

PEV Financial Incentives

In order to encourage PEV adoption, both the federal government and some states provide financial incentives. The federal government provides a tax credit of $2,500 to $7,500 for the purchase of BEV and PHEV vehicles, depending on the size of the battery pack. Vehicles with at least a four kWh battery pack are eligible for a $2,500 credit, and the maximum credit of $7,500 is available for vehicles with a battery pack larger than 16 kWh. All currently available PHEVs are eligible for at least a $2,500 credit, and those with the

Figure 1. Annual U.S. PEV Sales Since 2010



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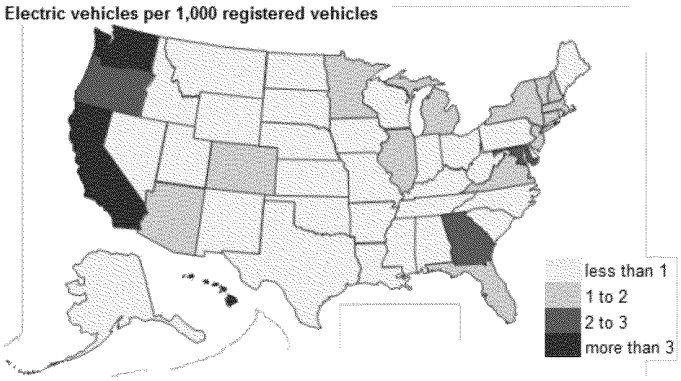
greatest all -electric range, such as the Chevy Volt, are eligible for a $7,500 credit. All currently available BEVs are now eligible for the full $7,500 credit. However, these credits will start to phase out for specific PEV models once the manufacturer has sold 200,000 vehicles.

Currently, 18 states also provide some form of financial incentive for the purchase of PEVs, ranging from state sales, excise, or personal property tax exemptions to tax credits or rebates. All state financial incentives apply to BEVs and some also apply to PHEVs. State tax credits and rebates are often expressed as a percentage of the PEV purchase price or a percentage of the PEV "cost premium" up to a cap amount.

Figure 2. PEV Adoption Rates, as of 2014



Source: EIA, based on data from R.L. Polk & Company

State caps on PEV incentives range from a low of $500 in Montana to a high of $7,500 in West Virginia. Other states with relatively high PEV purchase incentive caps include Colorado ($6,000), Georgia ($5,000), and Illinois ($4,000). Washington's exemption of BEVs from the 6.5 percent state sales tax results in a savings of $1,950 on a $30,000 vehicle. California provides rebates of $2,500 for a BEV or $1,500 for a PHEV.

In the Northeast, only Massachusetts and New Jersey provide state financial incentives for light -duty PEV purchases. Massachusetts offers a $2,500 rebate for purchase of a BEV or Chevy Volt and a $1,500 rebate for the purchase of most other PHEVs. New Jersey exempts BEVs from the state sales tax. While New York does not offer incentives for light -duty PEV purchases, it does have a rebate program for medium-duty BEV trucks.

Six states also allow EVs to travel in high occupancy vehicle lanes regardless of the number of passengers, and one exempts EVs from having to pay at public parking meters. Five states exempt EVs from emission inspection requirements. A number of states also provide additional tax credits for installation of electric vehicle charging infrastructure.

Current and Near Future PEV Offerings

There are eleven model year 2015 BEV models and eight model year 2015 PHEV models available in the U.S. from major auto manufacturers. Table 1 provides a summary of these vehicles. The vast majority of BEVs are two - and four-door compact sedans such as the Nissan Leaf, Volkswagen e-Golf, and Ford Focus EV, with price tags ranging from $23,000 to $35,000, and advertised range per charge from 62 to 87 miles. There are several luxury models available including the BMW i3 and Mercedes B - Class, with a price of approximately $42,000 but comparable size and range as the other compacts. The only true mid-size EV on the market is the Tesla Model S, which gets 208 miles per charge but has a price tag of almost $70,000. The all -wheel drive version of the Model S includes a larger battery pack that allows it to travel 270 miles on a charge but costs over $100,000.

Tesla plans to introduce the Model X in 2016, which is a seven-seat cross-over SUV with all-wheel drive. It will be available with two different sized battery packs, and the price and range per charge are expected to be similar to the two versions of the Model S. Tesla is also developing a compact sedan, which is expected to be introduced in the next few years, which will be priced similar to the BMW i3 but with greater range. Chevy also recently unveiled a concept Bolt EV (compact sedan) that is expected get 200 miles per charge and will be priced at approximately $37,000; Chevy has not yet indicated when it will be available.

While less numerous, plug -in hybrid models are somewhat more diverse, including both compact and mid -size sedans, and a luxury cross -over SUV. Prices for non - luxury plug -in hybrid models range from $32,000 to $40,000. All -electric driving range varies from six miles (Prius plug-in) to 38 miles (Chevy Volt).

Mercedes has announced that it will start to sell an S550 PHEV sedan and an ML Class PHEV cross -over SUV later this year and will introduce a compact sedan C350 PHEV in 2016. Hyundai will also introduce a PHEV Sonata for the 2016 model year that will have a reported 22

State MOU for Electric Vehicle Incentives

In 2013, California, Connecticut, Maryland, Massachusetts, New York, Oregon, Rhode Island, and Vermont signed a memorandum of understanding (MOU) to support the deployment of zero emission vehicles (ZEV), including BEVs and fuel cell vehicles. One of the major goals of the MOU is to deploy at least 3.3 million ZEVs and adequate fueling infrastructure within the eight states by 2025. To reach this goal, annual BEV sales over the next ten years will have to increase by 400% or more compared to 2014. In May 2014, the task force created by these states published a ZEV Action Plan, which identifies eleven priority actions to accomplish the goals of the MOU, including development of uniform standards related to vehicles and infrastructure; development of state - wide building codes to support installation of charging infrastructure; establishing ZEV purchase targets for government fleets and commitments for the use of ZEVs in state contracting; evaluation of additional monetary and non-monetary incentives for ZEV purchase; and development of a coordinated education and outreach campaign to promote the benefits of ZEVs.

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mile all-electric range. Chevy has indicated that the 2016 model year Volt will include an even larger battery pack, boosting all-electric range to 50 miles.

Vehicle Purchase Economics
Compared to the same or similar model gasoline vehicle, BEVs cost $12,000 to $19,000 more before federal and state rebates. However, after the state and federal tax credit, a Massachusetts resident, for example, would pay only $2,000 to $9,000 more for a BEV compared to the same or similar gasoline vehicle. A consumer that drives 10,000 miles per year would save about $290/year in fuel costs with a BEV, at current fuel prices ($2.07/gallon for gasoline and $0.125/kWh for electricity). Thus, the current, average pay-back period on the purchase of a BEV is seven to 29 years even with federal and typical state incentives. However, pay-back periods would be significantly shorter with fuel prices last year (average of $3.37/gallon). At last year's average prices, the annual fuel cost savings for a BEV could have been as high as $700, which would make the pay-back period, after federal and typical state incentives, as short as three years.

Table 1. Model Year 2015 PEV Offerings

Make	Model	Range	MSRP
Battery Electric Vehicles			
Tesla	Model S 85D	270 mi	$106,000
Tesla	Model S	208 mi	$71,000
Kia	Soul EV	93 mi	$33,700
Fiat	500 EV	87 mi	$31,800
BMW	i3	85 mi	$42,400
Nissan	Leaf	84 mi	$29,000
VW	e-Golf	83 mi	$35,500
Chevy	Spark	82 mi	$27,000
Mercedes	B Class EV	81 mi	$42,000
Ford	Focus EV	76 mi	$29,000
Smart	for two EV	68 mi	$25,000
Mitsubishi	i-MiEV	62 mi	$23,000
Plug-in Hybrid Vehicles			
Chevy	Volt	38 mi	$34,200
Cadillac	ELR	35 mi	$75,000
Porsche	Panamera S-e	20 mi	$99,000
Porsche	Cayenne S-e	20 mi	$76,000
Ford	C Max Energi	19 mi	$31,800
Ford	Fusion Energi	19 mi	$34,800
Honda	Accord	13 mi	$40,000
Toyota	Prius plug-in	6 mi	$30,000

Source: Fuel Economy.gov and manufacturer websites.

Compared to the same model hybrid vehicle, PHEVs with 10 to 20 miles all-electric range cost $7,800 to $10,700 more, or for a Massachusetts resident, for example, $3,800 to $6,700 more after the $2,500 federal tax credit and the $1,500 state rebate. Assuming that 50 percent of 12,000 annual miles were electric-only, the owner of the PHEV would save only about $30 per year at current average fuel prices, resulting in pay-back periods of more than 200 years for the purchase of a PHEV. However, at last year's $3.37/gallon for gasoline, annual savings could be almost $200 with a payback period of about 20 years.

By comparison, pay-back periods would be much shorter for a vehicle with a longer all-electric range, such as the Volt and because of its eligibility for larger federal, and potentially state, incentives. The incremental cost of a Volt is $14,000 compared to a gasoline Chevy Cruze Eco, or for a Massachusetts resident, for example, $4,000 after a $7,500 federal tax credit and a $2,500 state rebate. Assuming that 80 percent of the car's annual miles were electric-only, annual fuel cost savings would be $198 with current fuel prices, or $587 with gasoline at last year's average price. Thus, pay back periods would be about 20 years at current fuel prices, but as short as seven years if fuel prices rose to last year's higher levels.

Electric Grid Impacts and PEV Charging

Increased penetration of PEVs will inevitably increase electric load. While current PEV penetration rates should not create a near-term need for new generating capacity or transmission upgrades, the charge rate and time of day PEVs are refueled has implications for the cost of integrating PEVs into the electric grid, the cost of charging for the customer, and the environmental benefits associated with PEV adoption. For example, if PEV charging coincides with summer peak demand, this may result in greater reliance on less efficient peaking units, higher criteria pollutant and CO_2 emissions, upward pressure on wholesale market prices, and the need for upgrades to the distribution system.

However, a growing body of empirical data has shown that the added infrastructure costs associated with PEV charging can be minimized when utilities have the ability to create price incentives for PEV owners to charge their vehicles during off-peak hours when demand is lower, electricity costs are lower, and cleaner generating resources (such as wind and nuclear) are available. Emerging research and utility pilot programs are also evaluating the practicality and effectiveness of "utility managed charging"—where there is one- or two-way communication between the utility and the charging vehicles to start and stop charging and/or to control the charge rate of the PEVs, in order to manage over-all system load. Utility controlled charging is a significant departure from the existing model of PEV charging, in which decisions about when and how fast to charge are left to individual vehicle owners. However, it is analogous to other, existing utility load control programs in which specific loads are curtailed in response to a utility declared event.

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PEV Charging

Vehicle charging times vary based on the type of vehicle, type and size of the battery, and the capacity of the electric vehicle supply equipment (EVSE) used. The time to deliver a given amount of energy to a battery is determined by the voltage and current provided by the charging connection.

Industry and government entities have defined, and continue to refine, a set of EVSE standards that govern connector design and charging capacity. Level 1 EVSE provides charging through a 120 volt AC plug; the majority of PEVs come with a Level 1 EVSE cord set, and the vehicle can be charged by attaching to any standard household electrical outlet. Level 1 charging via a 20 amp household circuit adds about two to five miles of range per hour of charging time. Level 2 EVSE provides charging through a 240 volt or 208 volt electrical plug. Vehicle charging with Level 2 EVSE, therefore, requires the installation of special charging equipment and a dedicated higher voltage circuit. Level 2 charging can operate at up to 19.2 kW, but most residential EVSE will operate at 7.2 kW using a dedicated 40 amp circuit. Level 2 charging at 7.2 kW adds about 10 to 20 miles of range per hour of charging time.

Direct-current (DC) fast charging equipment, sometimes called DC Level 2 (typically 208/480 V AC three-phase input), enables much more rapid charging—potentially allowing an additional 50 to 70 miles of range to a PEV in about 20 minutes. However, these very high capacity EVSE increase the costs of charging and would typically only be deployed along heavy traffic corridors at public charging stations.

PEV Charging Behavior

To study and evaluate the development of PEV and charging infrastructure, the EV Project deployed over 12,000 AC Level 2 (208-240 V) charging units and over 100 dual-port DC fast chargers in 20 metropolitan areas. Based on data collected in the EV Project, on average, current PEV owners charge their vehicles between 1.1 and 1.5 times per day driven. Approximately 8,300 PEVs were enrolled in the project, and, according to EV Project data, the majority of PEV charging (approximately 80 percent) typically occurs at home. However, PEV drivers utilize workplace charging, when available, for a significant share of their overall charging. Evidence suggests that workplace charging could be important to PEV drivers who do not have easy access to home charging (e.g., owners who live in multi-unit apartment buildings). EV and EVSE manufacturers, policymakers, and environmental groups generally agree that greater PEV adoption may also be hampered by lack of public charging infrastructure given that most current BEVs can only go 90 miles or less per charge (see below). The Department of Energy (DOE) estimates that there are less than 10,000 non-home "electric charging stations" around the country, with fewer than 23,000 charging outlets; more than 26 percent of these charging outlets are in California. By comparison, there are over 114,000 public gas stations in the country.

In terms of at-home charging, the data from the EV Project shows that in areas where there are no special PEV charging rates or programs to incentivize off-peak charging, PEV owners plugged in their vehicles when they arrived home from work and immediately commenced charging. However, for those PEV owners that were offered a time of use (TOU) rate, the alternative rate provided an effective incentive for residential customers to delay the start of charging until the beginning of the off-peak rate period, when their charging costs would be lower. As a result, TOU rate customers did the majority of their charging off-peak. In order to allow owners to utilize TOU rates, virtually all PEVs available today provide the ability for drivers to plug in their vehicles when they arrive home, but program the vehicle to only start charging at some later time. Within the regions of the EV Project, eight electric utilities provide TOU rates: Arizona Public Service, Georgia Power, Los Angeles Department of Water and Power, Pacific Gas & Electric, Portland General Electric, Salt River Project, and San Diego Gas & Electric.

Customers facing stronger price signals are more likely to program charge start time into their vehicles and to adhere to a fixed PEV charging schedule based on utility pilot programs and the EV Project. EV Project TOU rate participants began the vast majority of their PEV charging events during off-peak periods, specifically between 12 AM and 2 AM.

PEV Clustering

It is unlikely that PEVs will be sufficiently deployed in the next 20 years to significantly affect total electrical system demand or to create a need for general transmission infrastructure upgrades. However, PEV "clustering" could create significant localized impacts at much lower penetration rates. Clustering refers to the potential for multiple PEVs in a single neighborhood, which could add significant load to a single residential service transformer. Clustering can result in high localized peak loads, longer transformer operation at higher power, and high power demand during off-peak hours. Implications of such results include damage to residential transformers by causing load to exceed the transformer's rating or by depriving it of its cool-down period during off-peak hours. This may result in premature replacement of the transformer and cause increased costs for the utility and its customer base.

The effects of PEV clustering are highly variable and localized and, therefore, hard to quantify. For example, consider a "typical" suburban neighborhood of single-family homes where nine houses are served from a 50 kVa service transformer, which could provide an average of approximately 6.4 kW per house before being dangerously overloaded. Each home (without a PEV) might have an average peak summer load of approximately five kilowatts during the late afternoon hours, but a load of only about two kilowatts during the early morning hours. In such a neighborhood the existing service transformer would have only about 12 kW of available capacity to accommodate PEV charging during

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late afternoon hours (4 PM to 8 PM) but would have as much as 39 kW of capacity to accommodate PEV charging during early morning hours (12 AM to 6 AM). The existing service transformer in this neighborhood of nine houses could accommodate only four PEVs charging simultaneously at average rates during the late afternoon without overload. However, the same transformer could potentially accommodate eight or more PEVs charging simultaneously during the early morning hours even if one or more were charging at a much higher than average rate.

At current penetration levels, widespread clustering has not been experienced by many utilities. However, high capacity charging (Level 2 (19 kW) and DC fast charging) has already created local distribution system impacts in some areas. Utilities did not construct local distribution networks and supporting transformers to handle household loads this high. The Tesla S is available with a 19.2 kW charger, which some owners have installed, but the vast majority of PEV owners rely on lower capacity chargers for home use due to the fact that vehicles typically remain at home for 10 hours or more per night —an adequate amount of time to fully charge the vehicle at rates well below 19 kW.

Utility Experience and Regulatory Considerations

Through the EV Project, pilot programs, and different EV rate offerings, utilities around the country have already learned significant lessons about consumer behavior related to PEV charging.

TOU rates, when properly structured, have been shown to provide customers with an economically attractive option for charging their PEVs, leading to desired changes in charging behavior (more charging during off-peak periods). However, there are several important considerations regarding TOU rates. First, there is the issue of whether to use TOU rates that apply to the whole house (whole-house TOU) or that apply to the PEV charging circuit (PEV-only TOU). In many ways, whole-house TOU rates are simpler and less costly for utilities to implement and are, therefore, preferred. There may also be regulatory barriers to implementation of PEV-only TOU rates in some states.

For customers who can switch the majority of their household electrical load to off-peak hours, whole-house TOU rates can provide a significant economic benefit. Houses with solar panels will likely also benefit from whole-house TOU rates since peak solar electricity production generally coincides with peak summer TOU rate periods, resulting in low net usage from the grid during day-time on-peak times. In reality, however, while many PEV owners probably can shift the majority of their PEV charging load to off-peak times, their remaining household electricity use likely would remain unchanged during day-time (on-peak) hours. As a result, any savings from off-peak PEV charging may be outweighed by higher on-peak prices for other household loads, negating any benefits from whole-house TOU pricing. In order to provide consistent net benefits to the majority of PEV owners, utilities need to consider PEV owners when structuring whole-house TOU rates.

SMUD PEV Study

Sacramento Municipal Utility District (SMUD) studied the costs of PEV adoption on the electric distribution grid within its service territory. The main focus of the analysis was the costs of upgrading the distribution grid to account for and support PEV integration. Overall, the study found that TOU rates can help reduce the costs of upgrading distribution infrastructure to accommodate for PEV adoption by lessening grid impact. However, TOU rates become less effective at reducing the costs of upgrading distribution infrastructure as charging capacity increases. The study concluded that in SMUD's network, smart charging can significantly reduce distribution infrastructure upgrade costs. However, smart charging can also negatively impact customer confidence in their ability to recharge vehicles. This concern can be mitigated by limiting demand response events to a set number over a period of time. Given that grid conditions will likely only require major charging interruptions several times per year, the overall impact on customers is minimal. Customer concerns could also be addressed through a variable charge rate. Under this scenario, the vehicle charge rate would decrease during a demand response event rather than cease entirely.

One of the largest impediments to PEV-only TOU rates is that the use of a second rate usually requires the installation of a second "utility grade" meter to measure electrical use on the PEV-charging circuit for billing purposes. In a two meter scenario, the main circuit would remain on the standard rate with only the PEV load connected to the TOU meter. Costs for a second utility grade meter are significant (often one thousand dollars or more up front plus an additional $10 to $20 per month) and, therefore, create a potential barrier to customer adoption of TOU pricing strategies for PEV charging. Sub-meters, either embedded in the EVSE or located on the vehicle, may provide a viable solution to a second meter, but would require PUC approval. In addition, no matter how the metering occurs, separate billing for a PEV charging circuit creates additional administrative burdens and costs for the utility to accommodate it.

Another potential method to incentivize off-peak charging by PEV owners would be an off-peak charging rebate program. Under such a program PEV owners would be offered a rebate on their monthly electric bill if, for a minimum number of days in the month (i.e., 26 out of 30), their PEV charging circuit was not drawing power during peak periods (e.g., 1 PM to 12 AM). Such a program would require the utility to monitor the PEV charging circuit, but would not require a utility grade meter since the data would not be used for billing. It is likely that a properly structured rebate program could function much like a PEV-only TOU rate, but with lower total implementation costs.

Managed PEV Future

Utility managed PEV charging programs, implemented either through the EVSE or the vehicle, could mitigate the

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potential grid impacts associated with the added load of PEV charging. Controlled charging can be employed by utilities to leverage PEVs as a flexible load to minimize the effects of PEV charging on the electric system.

Although the literature makes clear that controlled charging results in tangible benefits, actual controlled charging programs are in their infancy, and little information is available on the incentives required to encourage customer participation. Monetary benefits to PEV owners from participation in these programs must be balanced against actual or perceived disadvantages from loss of full control over their vehicle charging. Thus, while existing studies provide general suggestions on the incentives needed for controlled charging program adoption, real-world data are scarce. There are a number of pilot programs described below that may provide greater insights in the next few years.

EPRI and Sumitomo Electric Industries have collaborated to develop the Open Vehicle Grid Integration Platform (Open VGI Platform) software system. The Open VGI Platform is designed to facilitate communication between utilities and PEVs, enabling utilities to take advantage of the smart charging capabilities built into the vehicle. This system will enable the utility to communicate with the vehicle to adjust charging loads up or down or even to start or stop charging. In Phase 1 of the Open VGI Platform project, command signals were sent to vehicles to start and stop charging, which was deemed successful. In Phase II, from 2015 to 2017, the focus will be on exploring the potential benefits for electric utilities associated with managing charging loads. Phase II includes the following focus areas 1) residential demand response, 2) workplace fleet charging during the daytime, 3) distribution level DR, and 4) real time pricing.

Pepco created the Demand Management Pilot Program for Plug-In Vehicle Charging to encourage customers in Maryland to take advantage of off-peak charging. The pilot program offers discounted 'Smart Level 2" EVSEs. Enrollment is limited to 50 customers. Pepco will also pay 50 percent of the charging station's cost, and the customer will be responsible for the remaining balance (approximately $1,275). Pepco offers on-bill financing for EVSE installation cost. Pepco will use the smart EVSE to test demand response events and calculate the load impact of each event.

The NSTAR SmartCharging Pilot is a research project in Massachusetts for residential PEV charging designed to: (1) collect detailed charging profile data and (2) test communication with the EVSE to manage the charge rate. The pilot is available to 105 NSTAR customers and is scheduled to run for one year once the program is fully subscribed. NSTAR provides a subsidy for the EVSE so the cost to each subscriber is only $500. NSTAR will provide a $10 monthly bill credit if customers allow NSTAR to manage their daily charging. Customers are allowed to override NSTAR control of charging, but in order to qualify for the monthly incentive, no more than four overrides are allowed per month.

Finally, Con Edison is currently conducting a pilot program for 50 customers with PEVs in New York. The pilot is testing the ability of a Branch Circuit Energy Management Device (BCEMD) to measure, and to a limited extent, control PEV charging in five-minute intervals. In the pilot, Con Edison is also evaluating customer responsiveness to pricing and other information to evaluate its effect on charging behavior. Using command signals run through the communications portal developed for this pilot project, Con Edison is able to open and close contactors in the BCEMD, remotely turning charging on and off. Con Edison has conducted 27 utility control test events, with the participation of 21 pilot program customers. Each event lasted two minutes and removed between 0.1 and 9.6 kW of load. While the current BCEMB Con Edison is using in this pilot cannot vary the rate of charging, the utility is investigating similar technologies that could provide that capability.

Insights

Despite ever increasing PEV offerings from auto manufacturers and increasing numbers of PEVs on the road, it is unlikely that PEVs will have a major impact on the electric grid in the near future. However, even at today's penetration levels, PEV clustering could produce localized, negative impacts on distribution infrastructure at the neighborhood level. In order to plan for this risk, utilities need at least some notification that a customer has purchased a PEV and the type of EVSE they are using. With this information, utilities can better assess potential impacts on distribution transformers.

The majority of PEV charging currently occurs at home — a situation that is likely to continue. As PEV penetration increases, it will be important for utilities to develop simple, easily understandable pricing options that will incentivize PEV owners to charge their vehicles at off-peak times. Pricing options that appeal to customers can reduce grid impacts as well as the net cost and environmental impact of PEV charging.

Potential PEV charging pricing structure options include whole-house TOU rates, PEV-only TOU rates, and off-peak charging rebate programs. While TOU rates have proven successful in getting PEV owners to charge off-peak in some locations, other utilities have seen very low participation rates by PEV owners, limiting their impact. In order to achieve high levels of adoption, TOU rates, or other incentives, must provide actual and perceived net benefits to most PEV owners, must have a simple, easily understandable structure, and must be effectively promoted by utilities.

Ultimately, utility-controlled PEV charging may provide even greater net benefits to the grid than incentivizing off-peak charging, by leveraging PEVs as a flexible load, much like existing peak load management programs. However, it will be important to evaluate the costs of utility controlled charging and the incentives required to achieve high levels of customer participation.

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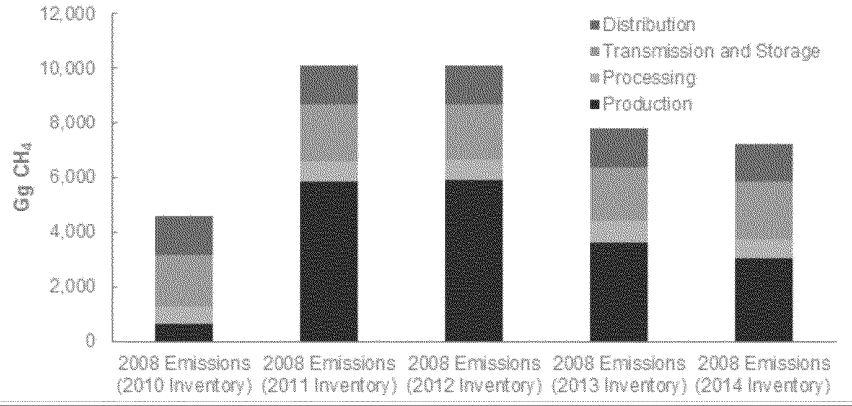
Estimates of Methane Emissions from Natural Gas Distribution Systems

Summary: As the Obama Administration and EPA focus on reducing total U.S. methane emissions (see *Methane Strategy Update* in the Summer 2014 issue of *Insights*), stakeholders have shown increased interest in EPA's methodologies for estimating methane emissions from natural gas systems. While EPA has made a number of updates to how it calculates emissions from certain upstream natural gas sources in the annual Greenhouse Gas Inventory, its methodology for distribution systems remains unchanged. A recent study by Washington State University provides data that EPA could use to update its current assumptions. This article compares EPA's estimates for methane emissions to the Washington State University study.

Each April, the Environmental Protection Agency (EPA) publishes the U.S. Greenhouse Gas Inventory Report (GHG Inventory) and submits it to the United Nations (U.N.) to fulfill obligations under the U.N. Framework Convention on Climate Change. As part of the GHG Inventory, EPA estimates methane emissions from natural gas systems. To develop the estimate, EPA divides natural gas systems into four segments (production, processing, transmission, and distribution) and estimates emissions associated with sources and activities in each segment.

EPA's basic methodology for estimating emissions from each segment is to (1) identify potential emission sources (e.g., leaks in a pipeline), (2) develop emission factors associated with each source (e.g., the amount of methane released annually by leaks per mile of pipeline), (3) estimate an activity level for the potential emission sources (e.g., miles of pipeline), (4) multiply emission factor by the activity level to estimate emissions associated with the source, and (5) add together estimated emissions for each source. For a number of sources, EPA adds an additional step of subtracting out emission reductions resulting from regulation or voluntary programs such as Natural Gas STAR.

Figure 3. 2008 Methane Emissions from Natural Gas Systems in EPA GHG Inventories: 2010-2014



Over the past several GHG Inventories, EPA has made a number of changes to the methodology for estimating emissions associated with natural gas systems. Figure 3 shows the effects of the methodological changes across the 2010 to 2014 inventories for the year 2008. As shown, the methodological changes have had the greatest impact on emissions from the production segment.

While EPA has focused on changes to the estimated emissions associated with production, Environmental Defense Fund (EDF) has been engaged in a broad initiative to quantify and better understand methane emissions from all segments of the natural gas value chain. One of the most recent studies to come out of the EDF initiative focused on the distribution segment. In a study published in March 2015, researchers at Washington State University (WSU) led a team that measured methane emissions from natural gas local distribution systems. The researchers took direct measurements of methane emissions from underground pipelines and metering and regulating (M&R) stations. The WSU study was done in coordination with 13 major natural gas utilities[1] and was sponsored by EDF with the American Gas Association, Con Edison, National Grid, Pacific Gas & Electric and Southern California Gas.

As discussed below, the researchers used their results to develop emission factors and replicate EPA's methodology for estimating emissions from the distribution segment. Their findings suggest that EPA may be significantly overestimating emissions from the distribution segment.

WSU Study Methodology

WSU-led researchers surveyed urban natural gas distribution systems at the 13 participating natural gas local distribution companies (LDCs) located throughout the U.S. The fieldwork, conducted in 2013, sought to compile a comprehensive set of direct measurements. Across the systems maintained by the participating utilities, researchers took direct measurements at 230 underground pipeline leaks and 229 M&R stations. Researchers did not take direct measurements at customer meters or during maintenance activities and mishaps. To incorporate these emissions, researchers used EPA's estimate for customer meters and LDC survey responses to update estimates for maintenance and mishaps.

For each participating LDC, measurements were taken in one city or region within the company's service area. Researchers recorded methane emissions at 10 to 20 pipeline

[1] The participating LDCs included National Grid, Con Edison, Columbia Gas of Pennsylvania, Piedmont Natural Gas, Atmos Energy (Texas), Citizens Gas (Indiana), CenterPoint Energy (Minnesota), Xcel Energy (Colorado), Questar Gas (Utah), Southwest Gas (Nevada), Northwest Natural Gas, Pacific Gas and Electric, and Southern California Gas Co. The participating companies hold 19 percent of the country's distribution pipeline mileage and 26 percent of its services. Cumulatively, they delivered 16 percent of all natural gas to customers in 2011.

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sources and 10 to 20 M&R station sources in each survey area. LDC survey data was used to randomly select the sources measured. The study did not measure leaks in winter and thus, does not examine the impact of frozen soil or increased wintertime gas throughput on emissions.

Methane Emissions Estimates in the WSU Study and GHG Inventory

WSU-led researchers used observed emissions to develop emissions factors for most of the distribution sources listed in the GHG Inventory. They then compared these emissions factors to those used in the GHG Inventory. The emissions factors used by EPA were developed in the mid-1990s through a research effort by the Gas Research Institute (GRI) and EPA and have not been updated since (GRI/EPA study). For nearly all sources surveyed, the new emissions factors were lower than the GRI/EPA emission factors. The report authors attribute these differences to emissions sampling techniques and equipment upgrades. The study also suggests that increased attention to maintenance and leaks is due in part to reporting requirements under EPA's GHG Reporting Program.

Pipelines

As Table 2 shows, emissions factors (average emissions per leak, in grams per minute) developed from the WSU study are generally lower than those developed from the GRI/EPA study and currently used by EPA to develop the national inventory. The 230 pipeline leak measurements taken during the study are more than twice the number of leak samples taken in the 1996 GRI/EPA study.

The report authors cite improved leak screening methods by LDCs, and differences in emissions sampling techniques between their study and the GRI/EPA study, as the primary reasons for the reduction in average emissions per leak. The distribution of emissions in the WSU study was skewed by three "super emitter" sources, which together accounted for 50 percent of total observed emissions from all of the pipelines tested. The WSU researchers used advanced statistical analysis to account for the distribution of super emitters when calculating their average emissions factors. By comparison, measured super emitters were given equal weight in the calculation of the GRI/EPA emissions factors, which overestimated their contribution to the average.

Table 2. Methane Emissions Factors for Underground Pipelines in the WSU and GRI/EPA Studies

Pipeline Type	GRI/EPA Emissions Factor (grams/min)	WSU Emissions Factor (grams/min)	Percent Change from GRI/EPA to WSU
	Mains		
Cast Iron	3.57	0.90	-75%
Unprotected Steel	1.91	0.77	-60%
Protected Steel	0.76	1.21	+59%
Plastic	1.88	0.33	-82%
	Services		
Unprotected Steel	0.74	0.33	-55%
Protected Steel	0.34	0.13	-62%
Plastic	0.11	0.13	+18%

M&R Stations

Similarly, the WSU study's emissions factors for M&R stations (average emissions per station, in grams per minute), developed from direct measurements, are significantly lower than those currently used by EPA for most sources (see Table 3). The differences are most pronounced at stations operating under higher pressures. To better understand the reason for these discrepancies, researchers measured emissions at nine facilities measured and identified as high emitting sources in the GRI/EPA study. These new measurements showed substantial reductions (factors of two to 50) at eight of the facilities. While information was not available for all sites, operators at two facilities indicated that there had been major equipment upgrades at these locations over the past 20 years. At the one site where emissions increased, no equipment changes had been made. Further, five participating LDCs, representing 90 of the M&R stations surveyed, indicated that approximately 60 percent of their facilities have been upgraded since 1992.

Table 3. Methane Emissions Factors for M&R Stations in the WSU and GRI/EPA Studies

Station Type (inlet pressure)	GRI/EPA Emissions Factor (grams/min)	WSU Emissions Factor (grams/min)	Percent Change from GRI/EPA to WSU
	M&R Stations		
>300 psi	57.4	4.06	-93%
100-300 psi	30.5	1.88	-94%
<100 psi	1.4	not measured	N/A
	Regulating Stations		
>300 psi	51.6	1.64	-97%
100-300 psi	12.9	0.27	-98%
40-100 psi	0.32	0.31	-3%
<40 psi	N/A	0.0	N/A
Vaults*	0.03-0.41	0.10	-76% to +233%

*All pressure categories are combined for underground vaults in the WSU study

The study's authors concluded that the lower emissions rates they observed today compared to those observed by GRI/EPA in the 1990s were a direct result of equipment improvements and facility rebuilds.

National Distribution System Methane Emissions Estimates

To estimate national annual emissions from distribution systems, the WSU study multiplied its new emissions fac-

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tors (those shown in Tables 1 and 2) by activity data from the GHG Inventory. When emissions factors derived from the study are scaled nationally, total U.S. distribution system emissions in 2011 are estimated by WSU to be 393 gigagrams (Gg) CH_4 (8.3 MMT CO_2e). This is 70 percent lower than EPA's estimate of 1,329 Gg CH_4 (27.9 MMT CO_2e) in the 2013 GHG Inventory. The WSU study suggests the U.S. natural gas distribution system contributes less than six percent of total natural gas system methane emissions compared to the 19 percent contribution estimated by EPA in the 2013 GHG Inventory.

When the upper bound of uncertainty (based largely on the skewed distribution of emissions) from the WSU study is applied, national emissions are estimated to be 854 Gg CH_4, which reflects a greater impact of super emitters on average emissions rates than the baseline calculation. This estimate is still 36 percent lower than EPA's estimate of distribution system emissions in the 2013 GHG Inventory.

Table 4 provides a breakdown of 2011 estimated annual emissions for each pipeline and M&R station type in the 2013 GHG Inventory, compared to estimated national emissions from the WSU study. As discussed above, lower estimates of the average emissions rate per leak are a major driver of the sharply lower estimate of total nationwide emissions in the WSU study compared to the EPA inventory. However, for underground pipelines, updated activity data also contribute to the WSU study's lower estimates.

The methodologies for both estimates use the concept of "equivalent leaks" to develop an estimate of the rate of leaks per mile of pipe or leaks per service. Equivalent leaks are based on pipeline leak and repair data reported by LDCs. To determine annual leakage per mile of pipe (g/mile/year), the average emissions per leak (g/year) is multiplied by the estimated rate at which leaks occur (leaks/mile). To estimate total emissions, the leak rate per mile is multiplied by the total miles of pipe.

The WSU study used new LDC data to develop new equivalent leak rate estimates, which, for most sources, were lower than the leak rate estimates GRI/EPA used to develop the emission factors that EPA still uses in the GHG Inventory. These lower equivalent leak rates, combined with lower estimates of average emission per leak, together result in lower emissions rates (in g/mile-year or g/service), and lower annual emissions, even when the primary activity data (pipeline miles and number of services) were held constant.

The percentage change in total annual emissions estimated by WSU for M&R/regulating stations, compared to EPA's inventory, is the same as the percentage change in the emission factors (g/min/station) shown in Table 3 because

Table 4. 2011 U.S. Methane Emissions in the 2013 GHG Inventory and WSU Study (Bscf/year)

Source Type	2013 GHG Inventory GRI/EPA Methodology	WSU Study	Percent Change from GHG Inventory to WSU
	Mains		
Cast Iron	7.82	2.02	-74%
Unprotected Steel	6.89	2.74	-60%
Protected Steel	1.46	1.84	+26%
Plastic	6.24	0.29	-95%
	Services		
Unprotected Steel	6.87	1.11	-84%
Protected Steel	2.63	1.75	-33%
Plastic	0.40	0.47	+18%
	M&R Stations		
>300 psi	6.02	0.438	-93%
100-300 psi	11.7	0.739	-94%
<100 psi	0.28	0.284	+1%
	Regulating Stations		
>300 psi	5.93	0.193	-97%
100-300 psi	4.49	0.096	-98%
40-100 psi	0.34	0.331	-3%
<40 psi	0.02	0.020	+0%
Vaults >300 psi	0.03	0.007	-77%
Vaults 100-300 psi	0.01	0.015	+50%
Vaults 40-100 psi	0.03	0.091	+203%
Total	61.4	12.4	-80%

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annual totals are based only on these emission factors and station counts.

Improving National Estimates

As it develops the GHG Inventory each year, EPA makes efforts to update its emissions estimates using the most recently available science and data. In recent years, this effort has led to significant changes in the methodology for calculating methane emissions from natural gas production. However, despite an expansion of the natural gas distribution network, pipeline replacement programs, and M&R station upgrades, EPA's methodology for estimating distribution-stage emissions has remained the same. Data from the WSU study could be used to update emissions factors for underground pipelines and M&R stations in the GHG Inventory.

Another potential source of data is EPA's GHG Reporting Program (GHGRP). The GHGRP requires LDCs with annual emissions greater than 25,000 metric tons CO_2e to report emissions. While the methodology for estimating emissions from mains and services relies on the GRI/EPA emission factors, LDCs are required to conduct leak detection surveys to quantify leak rates for above-ground M&R stations and certain components. These leak rates, which are updated at least once every five years, provide a more recent estimate of emissions as compared to the GRI/EPA emissions factors. EPA could look to the GHGRP data to improve the emissions factors for M&R stations used in the GHG Inventory.

Further, the GHGRP's approach to calculating M&R station activity data may be more appropriate than that used by the GHG Inventory. Under the GHGRP, LDCs provide an actual count of their M&R stations. In the GHG Inventory, the number of M&R stations is based on natural gas throughput. This means that activity data will change as throughput increases and decreases, even if there are no changes to actual infrastructure. The GHGRP approach of using actual station counts provides for more accurate emissions estimates and reduces volatility in annual activity data.

Additionally, in recent years, researchers and LDCs have worked to develop and field new methane leak detection and quantification technologies (See *Leak Detection and Methane Quantification by LDCs* in the Winter 2015 issue of *Insights*). Information collected by these technologies may also provide EPA with another source of emissions data.

Insights

Given that EPA has demonstrated an ability to incorporate new data into its methodologies for developing the national GHG inventory, the WSU data showing reduced emissions from the natural gas distribution system could be reflected in the 2016 GHG Inventory.

The significant investments LDCs have made in recent decades to modernize and maintain the safety of their systems have the co -benefit of reducing methane emissions. Even with this progress, opportunities remain to further reduce methane leakage from the distribution system, including additional pipeline replacements, reduction of pipeline blowdown emissions, and reduction of emissions from dig-ins and contractor damage.

Improving the GHG Inventory is a priority of the Obama Administration. The President's budget proposed $10 million to launch a program at DOE to enhance the quantification of emissions from natural gas infrastructure in coordination with EPA for inclusion in the GHG Inventory.

The Quadrennial Energy Review (QER) may help drive additional research on quantifying and reducing emissions from distribution systems. The QER's recommendations include: an increase in funding to improve and identify data gaps in the quantification of emissions from natural gas TS&D infrastructure; an expansion of natural gas transmission and distribution research and development programs to detect and reduce losses from natural gas transmission and distribution systems; and investment in research and development to lower the cost of continuous emissions monitoring equipment as a component of leak detection and repair programs.

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Allowance Allocation 101

Summary: Under EPA's proposed Clean Power Plan (CPP), states have the option of adopting either a rate-based target —expressed in CO_2 pounds per megawatt hour—or a mass-based target in tons per year; they also have broad discretion in designing the programs and policies included as part of their compliance plan. There are pros and cons with the various options available, and states will need to carefully consider their decisions once EPA publishes the final numbers. Given the interest that states and stakeholders have expressed for mass-based targets and mass-based trading programs, we thought it would be helpful to compile a refresher on the options available to states for distributing emission allowances under a mass-based trading program. The distribution of emissions allowances has always been a controversial topic going back to the Acid Rain SO_2 trading program, and is certain to be a topic for debate for states that choose to go down this path.

Methodologies for Distributing Allowances

In general, there are two basic options for distributing allowances under a mass-based trading program: (1) direct allocation, or (2) auction.

Direct Allocation

With a direct allocation approach, state authorities distribute allowances to affected sources without charge. The key issues in designing a direct allocation are (1) the basis to use in determining individual facility allocations, and (2) whether to update the distribution of allowances. Also, policymakers will need to decide what types of sources should be eligible to receive allowances. For example, states could include non-emitting energy sources under the allocation system.

When allocating to power plants, several metrics are available for apportioning the cap, including: the amount of fuel consumed (measured in British thermal units or Btus), the amount of electricity produced, or the quantity of CO_2 released to the atmosphere. For example, assuming an allocation based on historic CO_2 emissions, a facility would receive 10 percent of the allowance pool if it accounted for 10 percent of the CO_2 emissions produced by all regulated sources in the chosen baseline period. Most existing mass-based trading programs, such as the Acid Rain SO_2 trading program and the Clean Air Interstate Rule NOx trading programs, have relied on direct allocation approaches based on historic data (i.e., no updating).

An updating system would recalculate the allocation ratios on a regular basis (e.g., every three years). A static approach would calculate a facility's allocation once, and from that point forward the facility would receive the same share of allowances.

Auction

The auction approach requires that companies bid for a share of allowances with auction revenues collected (and redistributed) by the government. This is the approach used by the Northeast states in implementing the Regional Greenhouse Gas Initiative (RGGI) CO_2 trading program. Subsequent to the auction, companies are entitled to trade allowances or reduce emissions to ensure compliance with the cap. Auctions would take place at periodic intervals, allowing companies to adjust their compliance strategies.

The economic literature generally favors the auction approach because of the potential for an economically efficient outcome. However, companies faced with the prospect of making significant capital investments to reduce their emissions, in addition to having to pay for allowances, have been opposed to this approach in other market-based programs.

Table 5. Alternative Allocation Methodologies

	Direct Allocation	
	Updating	Static
Auction	**Allocation Metric** (e.g., heat input, generation output, historic emissions)	**Allocation Metric** (e.g., heat input, generation output, historic emissions)

Hybrids, Adjustment Factors, and Other Options

From these two basic approaches flow a myriad of options for designing or customizing an allocation system:

Hybrid Systems – A hybrid approach might combine an auction with a free allocation. For example, a limited share of the allowances might be available at auction in order to reveal a market price (e.g., to set penalties), with the remaining allowances distributed at no cost. The federal SO_2 trading program uses this approach with a limited auction set aside.

Price Caps – Policymakers have sometimes proposed price caps on the maximum price of allowances (sometimes called a "safety valve") when utilizing an auction approach. For example, the Clear Skies Act had proposed a cap on the price of allowances by allowing companies to purchase from a limited pool of allowances (i.e., future auction allowances) at a fixed price.

Transitional Programs – Options are available for transitioning from one form of allocations to another (e.g., from an input-based system to an output-based system).

Set Asides – Allowances can be set aside to meet specific policy objectives. For example, allowances might be set aside for new sources or specific types of sources (e.g., renewable energy projects).

Why Allocations Matter

The methodology employed for distributing allowances has always been a subject of controversy when establishing a mass-based trading program. A number of parties will have a stake in the outcome:

- Government can use the allocation process to influence policy outcomes, for example, by stimulating investment in clean sources of energy.

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- Some companies participating in the program will gain a competitive advantage as a result of the allocation methodology, while others lose a competitive advantage.
- Households and businesses that do not participate directly in the program also have a stake in the decision given the potential impact on energy prices and other products in the economy.

The Economics of Alternative Allocation Methods

There is a wealth of literature on the merits of mass-based trading, which is often contrasted with the relative inefficiency of command-and-control programs. In short, emissions trading directs capital investment to the least-cost control opportunities, minimizing the overall costs of compliance. Economists have also evaluated the relative efficiency of the alternative approaches for distributing allowances. Much of this work has focused on the electric generating sector. We briefly summarize the general principles.

To evaluate a policy, economists consider the incentives that result from government regulation. How will the policy influence behavior in the market? The best option is presumed to be the one that results in the lowest overall cost to society. (Transfer payments between companies and government, for example, are not considered costs in this context.). The distribution of costs (e.g., between households and industry) is a separate matter, which can also be evaluated.

Using computer models that simulate the operations of the U.S. electric generating sector, economists have calculated the costs of imposing a mass-based trading program on the sector with different allocation methodologies. This theoretical exercise suggests that auctioning is the most economically efficient approach for distributing allowances. A fixed allocation and an updating allocation are generally found to be less efficient. To arrive at these results, the scenarios are presumed to play out as follows:

An *updating, output-based allocation* is assumed to produce an output subsidy effect, undermining the efficiency of the program. With an updating approach, allocations are re-calculated on a regular basis based on a facilities' share of generation output. This affords companies the opportunity to earn a greater share of allowances by increasing their output. In order to accomplish this, a company has an incentive to reduce its prices, capturing a larger share of the market. Reducing its prices in the short-term will cost the company revenue. However, the operating assumption is that the value of the additional allowances earned will more than compensate for this loss.

Ironically, it is this incentive to *reduce* electricity prices that precipitates the higher overall costs of an output-based allocation. Reducing the price of electricity stimulates higher demand and reduces the incentive to invest in energy efficiency on the demand side. With more demand for electricity, existing power plants must increase their output and new power plants have to be built. All of this activity drives up the cost of policy. At the same time that new capacity is brought on-line, the industry must contend with the cap on emissions. This requires investment in low-carbon generating technologies (e.g., natural-gas combined cycle power plants). So while electricity prices will tend to decrease, the price of natural gas will tend to increase relative to its price under the other forms of allocation.

An *auction* is assumed to precipitate a somewhat different sequence of investment and demand response. Of the three options, the auction will stimulate the highest increase in electricity prices because companies are required to purchase their allowances. This triggers adoption of a wide range of measures for reducing greenhouse gas emissions. These include energy conservation, energy efficiency measures, and reliance on low carbon fuels. Unlike the updating, output-based allocation, which tends to

Table 6. Allocation Methodologies: Strengths and Concerns

Methodology		Strengths	Concerns
Distribution of allowances at no cost	Static allocation	Straight-forward approach that generally favors the sources that have historically produced the largest share of emissions (i.e., the companies with the largest compliance obligations)	Encourages the continued operation of older, lower efficiency sources because of the subsidy provided by the allocation and the barrier to new sources if they are forced to purchase allowances from the market
	Updating allocation	Offers the potential to encourage cleaner forms of electric power generation by rewarding efficiency	The moderating effect that an updating, output-based allocation might have on electricity prices would be favored by consumers, but may be a cause of concern for an industry faced with higher costs of compliance
Auction		Price signal drives economically efficient outcome, motivating cost-effective reductions throughout the economy	While the auction may reduce the costs of compliance, there is uncertainty regarding the broader economic implications of the policy. Also, the government would be left to manage a potentially large pool of revenues.

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focus more investment on low-carbon power generation, the auction stimulates a broader range of investments in order to meet the cap on emissions. Tapping into this diversity is what drives the economic efficiency of the auction. In summary, with higher electricity prices, electricity demand is reduced, fewer power plants are required to satisfy demand, power plants consume less natural gas (which moderates gas prices), conservation and efficiency measures are adopted to reduce the costs of consuming electricity, and the overall costs of the program are reduced.

Also, unlike the free allocation, the auction produces a stream of revenue to be managed by the government. The amount of revenue collected depends on the level of the cap and the exact rules of the auction. The way this money is used has important implications for the economic efficiency of the approach. The economic literature would argue that the least efficient option is to simply redistribute the funds (e.g., returning the revenues to households to offset their energy costs). The alternative would be to use the funds to reduce distortionary taxes such as the income tax. The need to resolve this issue is unique to the auction approach.

A *static allocation* (e.g., based on historic emissions) is similar to the updating approach in terms of its economic costs, but it lacks the output subsidy described above. Plant operators in competitive markets will reflect the price of allowances in their operating costs (even though they received the allowances for free) and electricity prices will increase. However, prices will not increase to the extent that they would under an auction; and absent the output subsidy, they will increase more than they would under an updating, output-based allocation. As described above, the overall costs of the policy will then flow from this price signal. Static allocation approaches based on historic emissions have been criticized as unfair because they reward sources with the highest emissions and penalize sources that have invested in low and zero emission sources.

Insights

Much of this article focused on the economic costs of the alternative approaches for distributing allowances, and the suggestion was that the method used for distributing allowances can influence the overall costs of the policy. This is an important conclusion; however, these cost differences have to be understood in a broader context. The level of the cap, the compliance schedule, and the decision to allow inter-facility trading are likely to have a far greater influence on the overall costs of the program than the choice of the allocation methodology. Allocation methodology would be a less significant determinant of the overall costs of the policy.

The efficiency gains of the alternative allocation methods are likely to be strongly influenced by the level of the cap. If the policy is seeking significant emission reductions, requiring numerous control strategies to be implemented throughout the economy, an auction is likely to be the most efficient option because of its strong price signal. The price signal will do a good job of motivating the implementation of cost-effective control strategies, including conservation measures. With a less stringent target and fewer compliance strategies required to comply with the target, the relative advantage of an auction will diminish.

Beyond economic considerations, states and stakeholders will also examine additional factors in evaluating the allocation options. For example, what are the incentives for and barriers to technological innovation that result from the policy? What are the costs of administering the policy? Is the approach scalable, allowing additional industry sectors to be integrated into the program? What are the distributional effects of the policy (i.e., who wins and who loses)? These and other factors will influence the political dynamics that ultimately lead to a decision on the best approach for distributing allowances.

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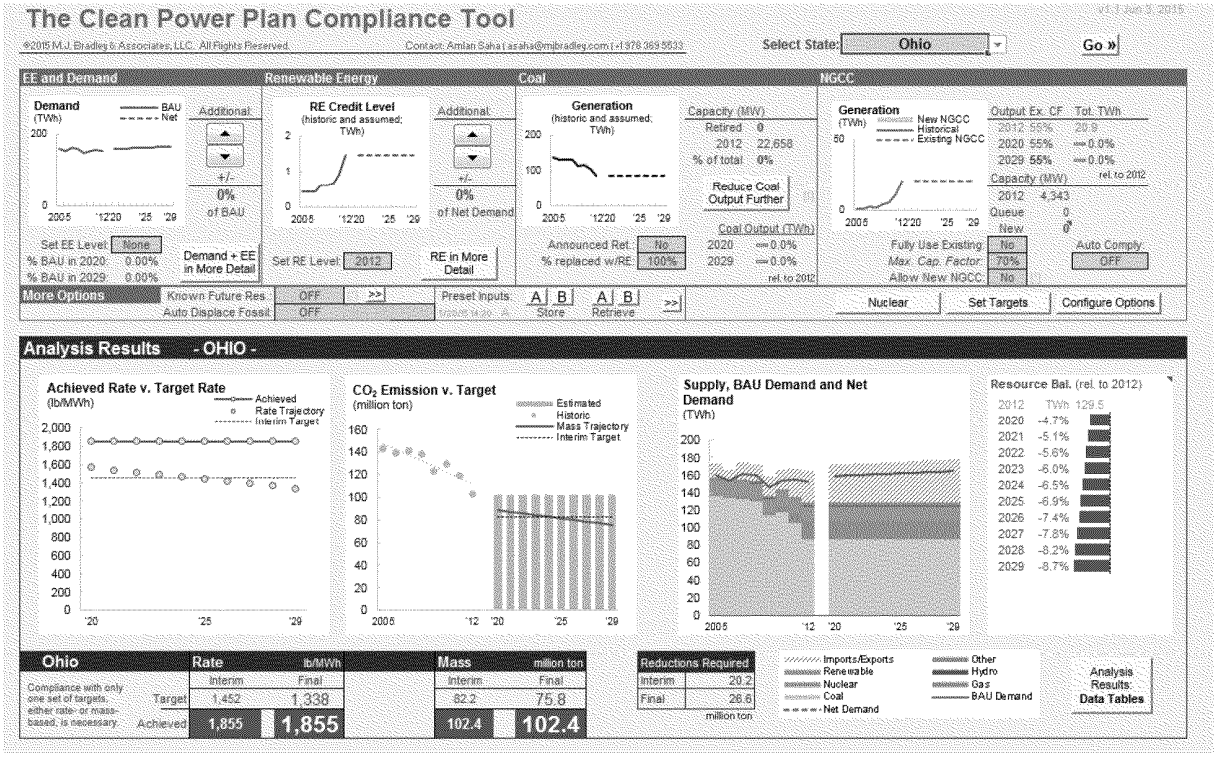
MJB&A Clean Power Plan Compliance Tool



In May 2015, MJB&A released its Clean Power Plan (CPP) Compliance Tool. The Excel-based tool allows users to analyze state progress towards compliance with the proposed CPP under a range of electricity demand and generation scenarios and a variety of emissions reduction targets. The Tool incorporates policy options outlined in the proposed rule, and provides the ability to alter all major drivers of state electric sector emissions and ascertain their impacts on state CPP compliance status. Results are automatically analyzed and displayed based on changes made by the user in a variety of graphs to track how each option influences compliance with interim and final targets.

The Compliance Tool can incorporate data from MJB&A's CPP Evaluation Tool, which allows users to adjust dozens of parameters to recalculate individual state goals.

Registration for both tools is at http://www.mjbradley.com

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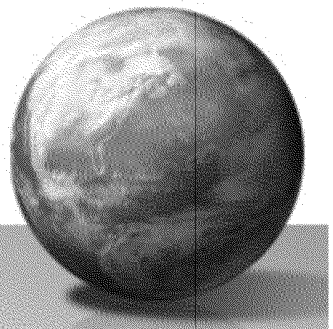


Inventory of U.S. Greenhouse Gas Emissions and Sinks

GHG Reporting Program vs. GHG Inventory

	U.S. GHG Inventory (UN Requirement)	GHG Reporting Program (Facility Reporting by Regulation)
Scale	• National	• Facility

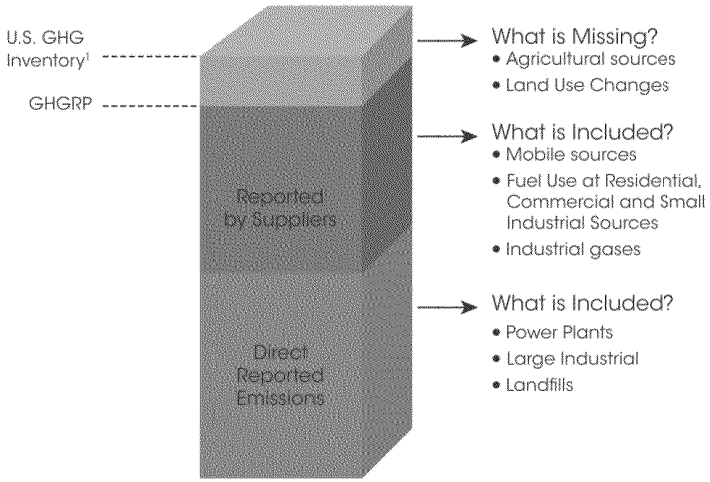
Coverage	• All U.S. anthropogenic emissions
	  • Energy
	  • Industrial Processes
	  • Agriculture and Land Use
	  • Waste
		• ~55% US direct anthropogenic emissions
		• ~30% US indirect anthropogenic emissions (e.g., fuel & chemical suppliers)
		• Over 8,000 facilities
		• Facilities > 25,000 metric tons CO2 equivalent per year
		• Excludes agriculture

GHGs	• CO_2, CH_4, N_2O, Fluorinated GHGs	• CO_2, CH_4, N_2O, Fluorinated GHGs
Methods	• IPCC higher "tier" • Mix of measurement-based emission factors, models, and GHGRP data	• Mix of measurement (continuous, periodic measurements, and sampling), and engineering calculations & emission factors
Time series	• 1990 – present	• Annually, since 2010

EPA GHG Emissions Data Programs

- Inventory of U.S. Greenhouse Gas Emissions and Sinks (Inventory) tracks total annual U.S. emissions across all sectors of the economy using national-level data
- GHGRP collects detailed emissions data from large greenhouse gas emitting facilities in the United States
  - GHGRP covers most, but not all, U.S. GHG emissions
  - GHGRP does not include agriculture, land use, and small sources

GHGRP Covers the Majority of U.S. GHG Emissions



[1] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011, April 2013.

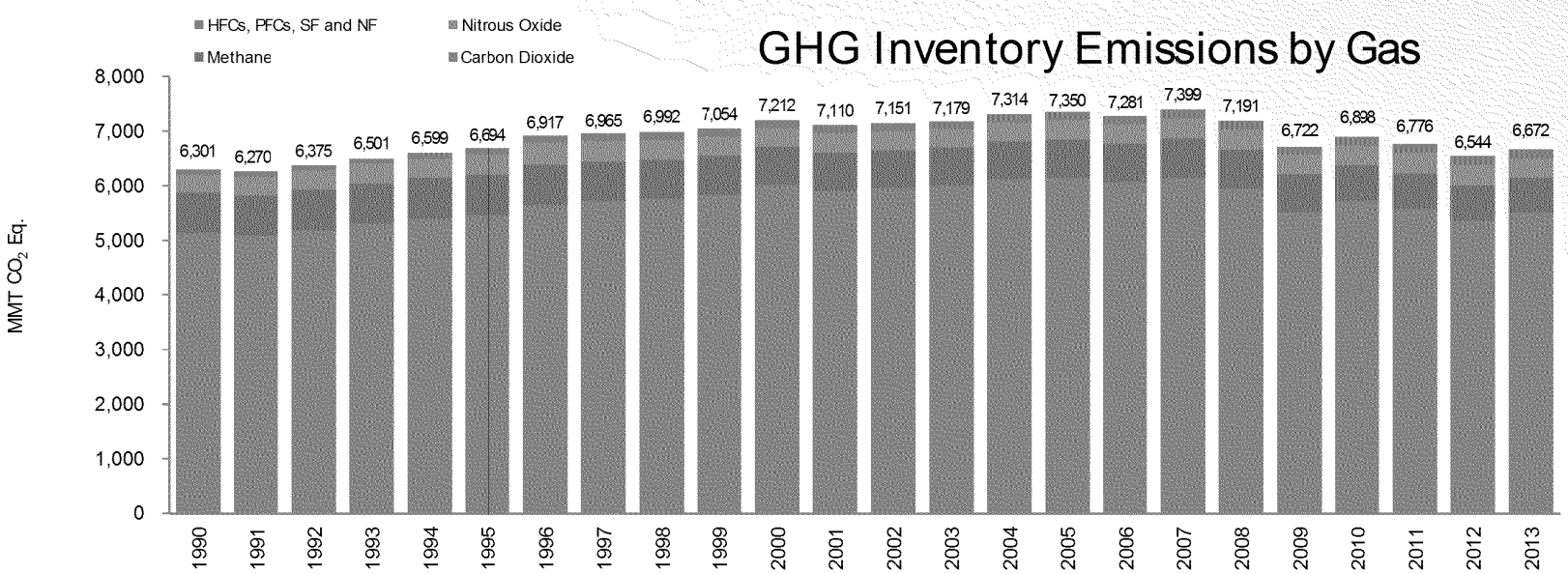
Task	Inventory	Greenhouse Gas Reporting Program
Find total U.S. emissions	✓	
Review trend data for the past 20 years	✓	
Browse a map to find largest emitters in your area		✓
Compare facility emissions across an industrial sector		✓
Find reported emissions by state		✓

U.S. Greenhouse Gas Emissions Inventory

- Official U.S. estimate of greenhouse gas emissions for reporting to United Nations Framework Convention on Climate Change (UNFCCC)
  - Annual national-level inventory submissions to the UNFCCC since 1994
- EPA leads Inventory development, working with several agencies
  - e.g. input data on forestry from USFS, data on energy from EIA
- Sectors Covered
  - Energy, Industrial Processes, Agriculture, Land-Use Change and Forestry, and Waste
- Gases Covered
  - CO_2, CH_4, N_2O, HFCs, PFCs, SF_6
  - Reported in Gg of each gas, and as global warming potential (GWP)-weighted CO_2e emissions
- Record of emissions trends over time
- Each year, Inventory undergoes expert review, public review, and UNFCCC review

2015 GHG Inventory Results Overview

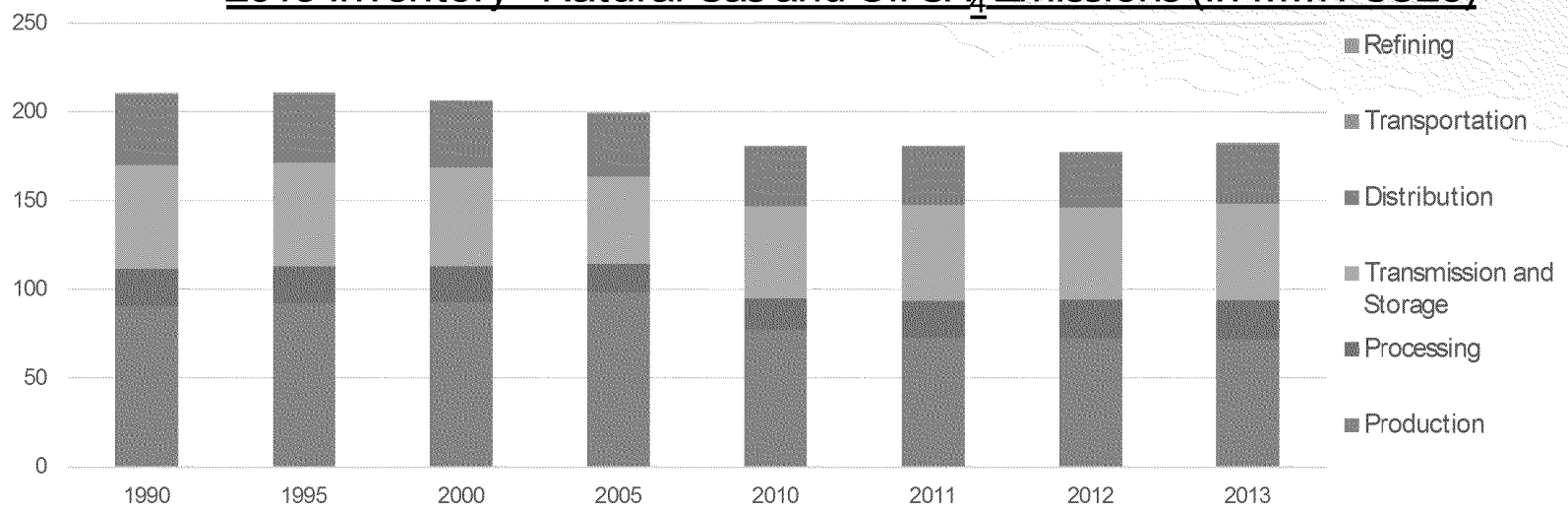
- US GHG emissions increased 2% from 2012 to 2013
  - Increase of 6% from 1990, decrease of 9% from 2005
- CO_2 from fuel combustion dominate emissions and trends
  - Major contributor to increase in emissions was increased energy consumption across all sectors in the U.S. economy, and increases in the carbon intensity for electricity generation due to increased reliance on coal generation in 2013



Oil and Gas Emission Estimates in the US GHG Inventory

- Oil and gas CH_4 account for 3% of total U.S. GHG emissions, and 29% of U.S. CH_4 emissions
- 183 Tg CO_2e total CH_4 emissions from oil and gas systems
  - 71 MMT CO_2e from oil and gas production segments
  - 23 MMT CO_2e from processing segment
  - 55 MMT CO_2e from transmission and storage segment
  - 33 MMT CO_2e from distribution segment
- Emissions decreased 28 Tg CO_2e, or 13%, from 1990-2013
- EPA continues to update estimates to reflect best available information

2015 Inventory - Natural Gas and Oil CH_4 Emissions (in MMT CO2e)



Calculation of National Emissions

- Calculation: regional versus national
  - Natural Gas production: regional estimates compiled to national
  - All other segments calculated at national level
- Methods
  - Net calculation approaches
  - Potential methane and subtraction of Gas STAR reductions
- Emission factor data sources
  - GHGRP
  - GRI/EPA
  - Others

Calculation: Net Factor Approach

- Approach uses activity data and emission factors distinct for control type categories

<u>Calculation of National Emissions</u>
Step 1. Compile activity data on controls
Step 2. Calculate Net Emissions-Apply net emission factors to the corresponding control categories

Example: Calculation of CH4 from HF Gas well completions and workovers

	Activity Data Emission	Factor (tons CH4 per C/W)	Emissions (tons CH4)
HF C&W that vent	1,677	36.8	61,737
HF C&W that flare	835	4.9	4,100
HF C&W with RECs	3,156	3.2	10,229
HF C&W with RECs+flare	2,117	4.9	10,326
Total	7,775	N/A	86,392

Calculation: Potential Factor Approach

- Approach uses GRI/EPA study with detailed equipment counts, emissions measurements and development of emission factors, updates with recent survey data

Calculation of National Emissions

Step 1. Calculate Potential Methane

- Collect activity data on production and equipment in use and apply emission factors (i.e., scf gas per unit or activity)

Step 2. Compile Reductions Data

- Calculate the amount of the methane that is not emitted, using data on voluntary action and State regulations

Step 3. Calculate Net Emissions

- Deduct methane that is not emitted from the total methane potential estimates to develop net CH_4 emissions

Example: 2012 Emissions from pneumatic devices in transmission sector (2014 Inventory)

Activity Data (# of pneumatics)	Emission Factor (Scf/device)	Calculated Potential ($MMTCO_2e$)	Reductions ($MMTCO_2e$)	Emissions ($MMTCO_2e$)
70,827	x 162,197	= 4.7	- 0.3	= 4.4

Increasing Stakeholder Interest in CH_4

- Interest in EPA estimates
  - Many changes in natural gas industry practices in recent years
    - e.g. hydraulic fracturing; control technologies
  - General interest in role of short-lived climate forcers
  - Fuel-switching implications
    - e.g. power and transport sectors
- Increased EPA engagement with stakeholders
  - Expert and public review processes of the GHG Inventory
  - Stakeholder workshops and webinars
  - External studies
- Stakeholder data and information has led to recent improvements in GHG Inventory estimates

Recent Updates to GHG Inventory for Oil and Gas

Inventory Year	Update to GHG Inventory Natural Gas Systems Estimate
Inventories through 2010	• GHG estimates for all activities were based on a 1996 GRI/EPA study (1992 data)
2011/2012 Inventories	• Updated estimates of liquids unloading using engineering calculations • Included hydraulically fractured (HF) gas well completions/workovers
2013 Inventory	• Further improvements to liquids unloading estimates using API/ANGA study • Updated HF gas well completions/workovers estimates
2014 Inventory	• Update to approach for estimating emissions from HF gas well completions/workovers to use GHGRP data
2015 Inventory	• Improved data source for well counts • Updated data for offshore oil and gas platforms • Updated GHGRP data for HF gas well completions/workovers • Use of GHGRP data for refineries • Reallocating Gas STAR pneumatic controller reductions

11

Updating GHG Inventory Estimates

- GHGRP
- External study data

Updating Estimates for Future GHG Inventories

- Enhancing the US Greenhouse Gas Inventory is a key part of the Climate Action Plan Strategy to Reduce Methane Emissions
  - Incorporation of GHGRP
  - Work with USDA and DOE
  - Promoting transparency and stakeholder input
- Evaluation of updates to estimates key to maintaining GHG Inventory quality
  - Continuous improvement - if better data become available, IPCC good practice and UNFCCC obligates its consideration
  - Emphasis on improving estimates and devoting resources to large sources, or rapidly changing sources ("Key Sources")
  - Annual reassessment of methodologies and refinements for each source category
- EPA notes updates under consideration in "Planned Improvements" section of Inventory

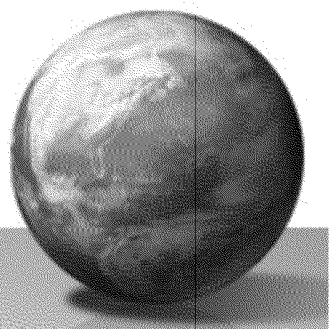
Consideration for Use of GHGRP data in Inventories

- Threshold
  - Methods to develop national estimate
  - No threshold-petroleum refineries
  - GHGRP activity data versus national activity data
  - Use of input data to assess coverage (e.g. well counts comparison to national well counts)
- Methods
- Exit ramp

Oil and Gas GHGRP data in GHG Inventory

- Use of GHGRP data to update methods
  - Use of GHGRP data to update HF emissions methodology with practice-specific factors instead of potential factor
  - Petroleum refineries-replacement of GHGI estimate
- Future use of GHGRP
  - Activity data available in 2015
- QC of GHGI estimates and identification of areas for review
  - Sources where GHGRP indicates over- or under- estimates
    - E.g., Liquids unloading update to 2013 Inventory
      - 2012 Inventory total emissions significantly higher than GHGRP results
      - GHGRP data used to validate a new data sources and updated emissions totals
  - Evaluation of regional GHGRP data compared to GHGI regional data
  - Evaluation of GHGRP trends compared to GHGI trend for recent years

General Criteria for Evaluating External Studies



- Representativeness (national, regional, production-level, emissions-level)
- Data on controls, practices, and other relevant information
- Availability of relevant activity data
- Ability to develop emission factors and activity data for the time series
- Robust and transparent sampling approach, measurement method, and key background data

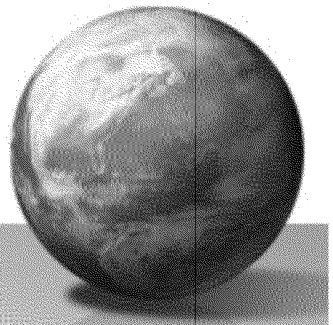
Methane Measurement Studies

- Several recent studies have measured CH_4 emissions at the national or regional level, with estimates that differ from EPA's emissions estimate
  - Some studies compare to EPA inventory; some to other bottom-up data
- EPA is considering how such measurement studies can be used to update Inventory estimates
  - Verification tool?
  - Prioritizing sources for improvement?
  - Incorporation into inventory?
- Some factors for consideration
  - Attribution—including calculations and assumptions regarding natural sources of emissions and other emissions that are not the target of the study
  - How such measurements can inform emission factors and activity data used to calculate a time series for national emissions

Role of Methane Measurement Studies in Improving Inventories

Type of Study	Example	Feedback to inventories
Assessing effectiveness of global efforts to reduce emissions through trends in atmospheric concentrations	IPCC Assessment Reports	• n/a
Independent verification of inventory estimates through inverse modeling	NOAA verification studies	• General conclusions about potential over- and under-estimates • Source attribution is a challenge • Limited ability to pinpoint which data inputs need to be improved
Measurement of specific activities, processes and equipment to develop improved emission factors	UT-Austin/EDF studies	• Direct improvements, if measurements are representative • Sample size and access to facilities can be a challenge

Key Considerations for Policy-Relevant Measurement Studies



- Top down
  - Using the right bottom up Inventory comparison
    - EDGAR is not U.S. GHG Inventory
    - Seasonal/regional variations important
    - Natural sources
  - Clearly communicating assumptions and uncertainties
- Bottom up
  - Providing information on activities taking place at the time of measurement and their national/regional representativeness
    - General operating conditions
    - High-emission venting events
    - Controlled versus uncontrolled

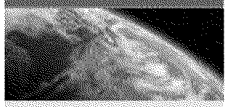
Accessing EPA GHG Data

- U.S. GHG Inventory (National-level data)
  - http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html
- Facility-Level GHGRP Reporting Data
  - http://www.epa.gov/ghgreporting/

Greenhouse Gas Emissions Data

Information and data about greenhouse gas emissions are available at the global, national, facility, and individual levels.

Global



Find out more about global greenhouse gas emissions and trends.

Learn More »

National

Review *EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks* report, which contains annual estimates of greenhouse gas emissions and removals associated with human activities, for each year since 1990.

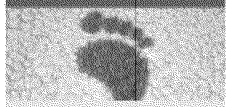
Learn More »

Facility

Explore facility-level greenhouse gas data collected through EPA's Greenhouse Gas Reporting Program data. You can view emissions from individual facilities or from many facilities organized by sector or state.

Learn More »

Individual



Use EPA's Individual Greenhouse Gas Emissions Calculator to estimate your carbon footprint.

Learn More »

FOIA EPA-HQ-2018-0005849

Petroleum and Natural Gas Systems in the Greenhouse Gas Reporting Program

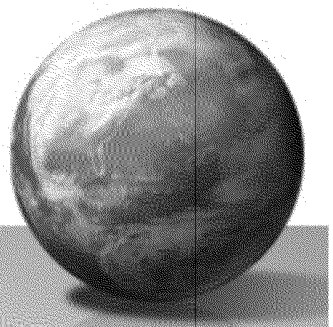
U.S. Environmental Protection Agency
Office of Atmospheric Programs, Climate Change Division

ED_001785D_00003610-00001

Overview of GHG Reporting Program

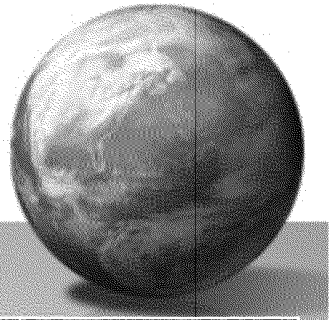
- Launched in response to FY 2008 Consolidated Appropriations Act
- Annual reporting of GHGs by 41 source categories
  - 33 types of direct emitters
  - 6 types of suppliers of fuel and industrial GHGs
  - Facilities that inject CO_2 underground for geologic sequestration, enhanced oil recovery, or any other purpose
- Most source categories began collecting data in 2010, with first annual reports submitted to EPA in September 2011
  - An additional 12 source categories began collecting data in 2011, with first annual reports submitted to EPA in September 2012
  - We now have 5 years of data for 29 source categories and 4 years of data for 12 source categories
- Facilities use uniform methods prescribed by the EPA to calculate GHG emissions, such as direct measurement, engineering calculations, or emission factors derived from direct measurement
  - In some cases, facilities have a choice of calculation methods for an emission source

Overview of GHG Reporting Program



- An estimated 85-90 percent of the total U.S. GHG emissions from over 8,000 facilities are covered by the GHGRP.
- Reports are submitted annually on March 31 for emissions in the previous calendar year.
- Annual reports are submitted to EPA electronically using an electronic greenhouse gas reporting tool (e-GGRT).
- EPA verifies the data submitted.
- Emissions data are published through several websites, including FLIGHT (ghgdata.epa.gov).

Source Categories Covered by GHG Reporting Program



Power	Refining & Petrochem	Other Chemicals	Combustion	Waste	Metals	Minerals	Pulp & Paper	High GWP Gases
- Electricity Generation - Electrical Equipment Mfg. - Electrical Equipment Use	- Petroleum Refineries - Petrochem. Production	- Adipic Acid - Ammonia - Hydrogen Production - Nitric Acid - Phosphoric Acid - Titanium Dioxide	- Stationary Combustion	- Industrial Waste Landfills - Industrial Wastewater Treatment - MSW Landfills	- Aluminum - Ferroalloy - Iron & Steel - Lead - Magnesium - Silicon Carbide - Zinc	- Cement - Glass - Lime - Misc. Carbonate Use - Soda Ash	- Pulp & Paper	- Electronics Mfg. - Fluorinated GHG Production - HCFC-22 Prod./HFC-23 Destruction - Pre-Charged Equipment Import/Export - Industrial Gas Suppliers

Petroleum & Natural Gas Systems	Fuel Suppliers	Carbon Capture & Sequestration	Mining
- Onshore Production - Offshore Production - Natural Gas Processing - Natural Gas Transmission/Compression - Natural Gas Distribution - Underground Natural Gas Storage - Liquefied Natural Gas Storage - Liquefied Natural Gas Import/Export	- Coal-Based Liquid Fuels Suppliers - Natural Gas and Natural Gas Liquids Suppliers - Petroleum Product Suppliers	- Geologic Sequestration of CO_2 - Injection of CO_2 - CO_2 Suppliers	- Underground Coal Mines

Direct Emitters
Suppliers
CO_2 Injection

GHG Reporting Program vs. US GHG Inventory

- Inventory of U.S. Greenhouse Gas Emissions and Sinks (Inventory) tracks total annual U.S. emissions across all sectors of the economy using national-level data
- GHGRP collects detailed emissions data from large greenhouse gas emitting facilities in the United States
  - GHGRP covers most, but not all, U.S. GHG emissions
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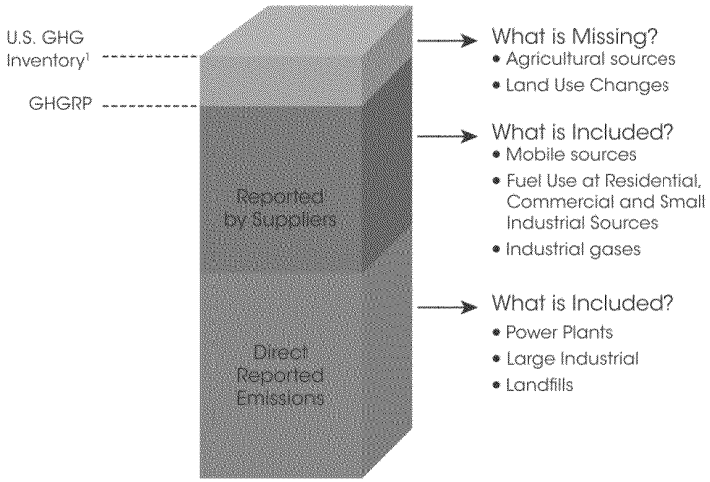
GHGRP Covers the Majority of U.S. GHG Emissions

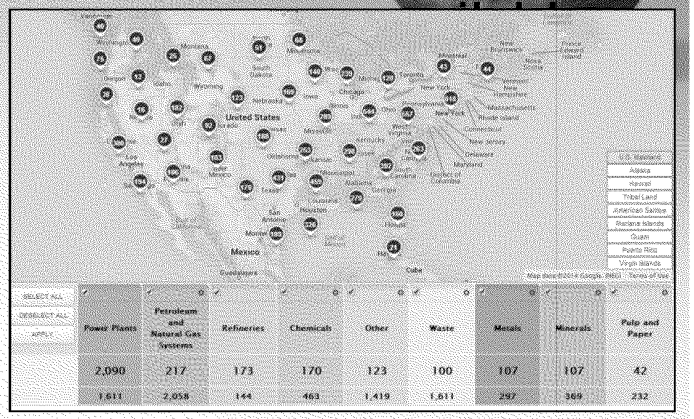


[1] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011, April 2013.

Task	Inventory	Greenhouse Gas Reporting Program
Find total U.S. emissions	✓	
Review trend data for the past 20 years	✓	
Browse a map to find largest emitters in your area		✓
Compare facility emissions across an industrial sector		✓
Find reported emissions by state		✓

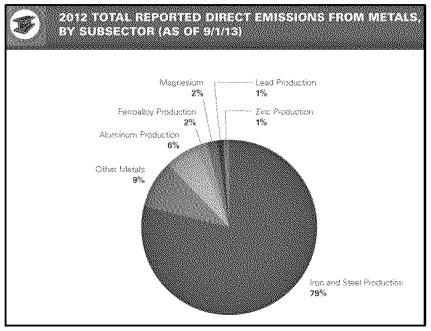
Data Publication - FLIGHT

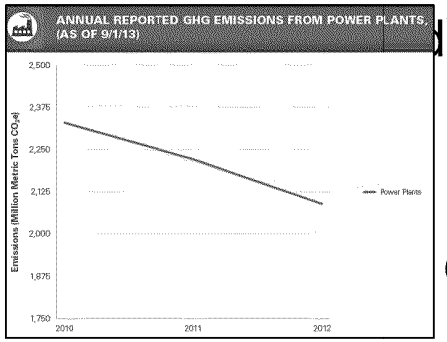
- EPA makes GHGRP data publicly through several websites
- FLIGHT (http://ghgdata.epa.gov)
  - Allows stakeholders and the public to access the key data elements quickly and easily



- Envirofacts (http://www.epa.gov/enviro/facts/ghg/customized.html)
  - Contains all publicly available data collected by the GHGRP

- Data Highlights (http://www.epa.gov/ghgreporting/ghgdata/reported/index.html)
  - Contains a summary of data in each sector





GHGRP Petroleum and Natural Gas Systems (Subpart W)

Petroleum and Natural Gas Systems in GHGRP (Subpart W)

Production and Processing
1. Onshore Production
2a, 2b. Offshore Production
3. Gathering and Boosting (not covered by Subpart W)
4. Natural Gas Processing

Transmission and Storage
5. Natural Gas Transmission
6. Underground Natural Gas Storage
7. LNG Storage
8. LNG Import-Export

Distribution
9, 10. Natural Gas Distribution

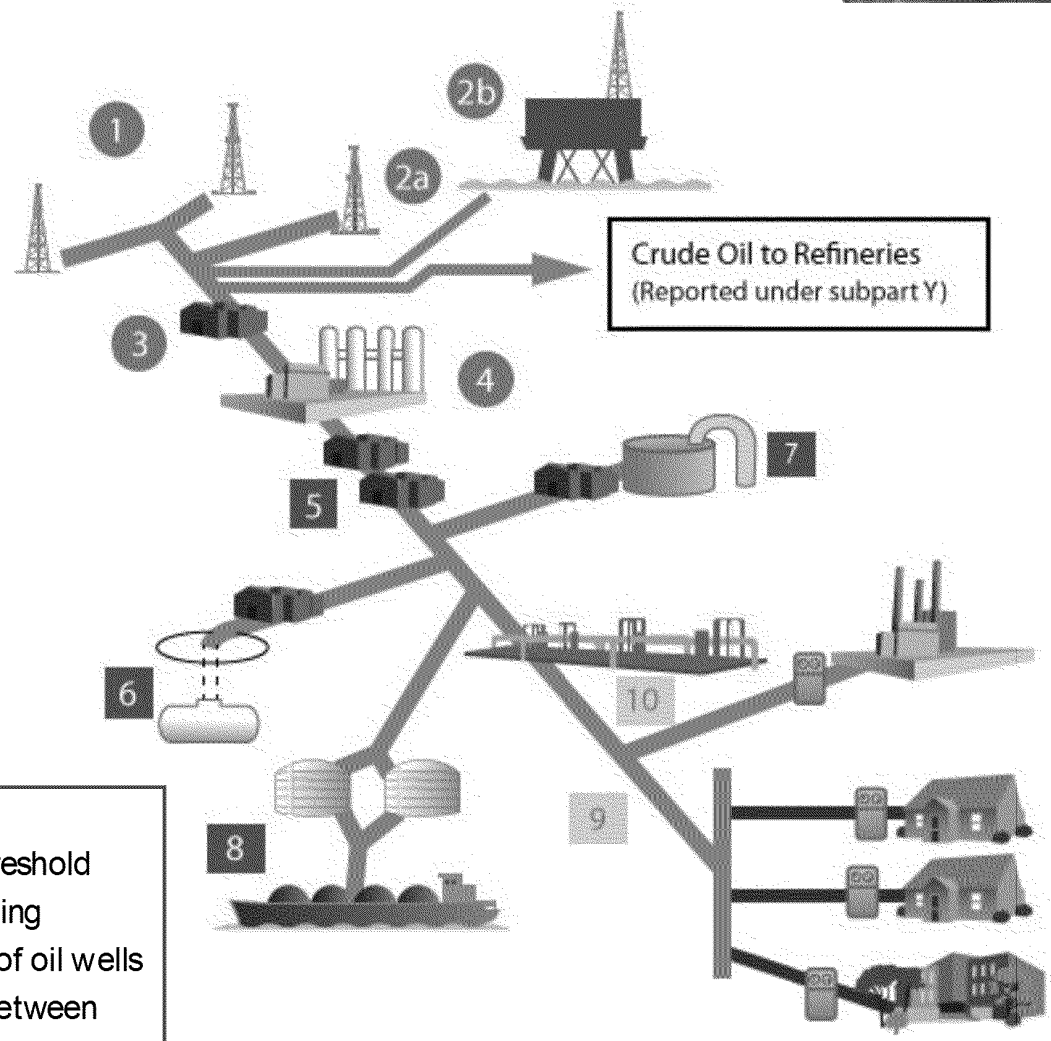


Figure adapted from AGA and Natural Gas STAR

Not Covered
- Emissions below 25,000 metric ton CO_2e threshold
- Process emissions from gathering and boosting
- Vented emissions from hydraulic fracturing of oil wells
- Process emissions from transmission lines between compressor stations

What is a Facility?

- In general, a "facility" for purposes of the GHGRP means all co-located emission sources that are commonly owned or operated
- However, certain industry segments within the Petroleum and Natural Gas Systems source category have unique "facility" definitions
  - Onshore production: the "facility" includes all emissions associated with wells owned or operated by a single company (the permit holder) in a specific hydrocarbon producing basin (as defined by the geologic provinces published by the American Association of Petroleum Geologists)
  - Natural gas distribution: the "facility" is a local distribution company as regulated by a single state public utility commission
- The other industry segments in the Petroleum and Natural Gas Systems source category follow the general GHGRP definition of "facility"

2013 Reported GHG Emissions from Petroleum and Natural Gas Systems

Reported GHG Emissions by Industry Segment

- EPA received annual reports from over 2,000 facilities
- Reported emissions totaled 224 Million Metric Tons (MMT) CO_2e
- Largest segments in terms of reported GHG emissions were onshore production, natural gas processing, and natural gas transmission

Segment	Number of Facilities	2013 Reported Emissions (Million Metric Tons CO_2e)
Onshore Production	503	95
Offshore Production	107	6
Natural Gas Processing	433	59
Natural Gas Transmission	487	23
Underground Natural Gas Storage	48	1
Natural Gas Distribution	173	15
LNG Import/Export	8	< 1
LNG Storage	5	< 1
Other Oil and Gas Combustion	415	25
Total	2,164	224

GHGRP data as of 8/18/14

Changes in Reported Emissions: 2011-2013

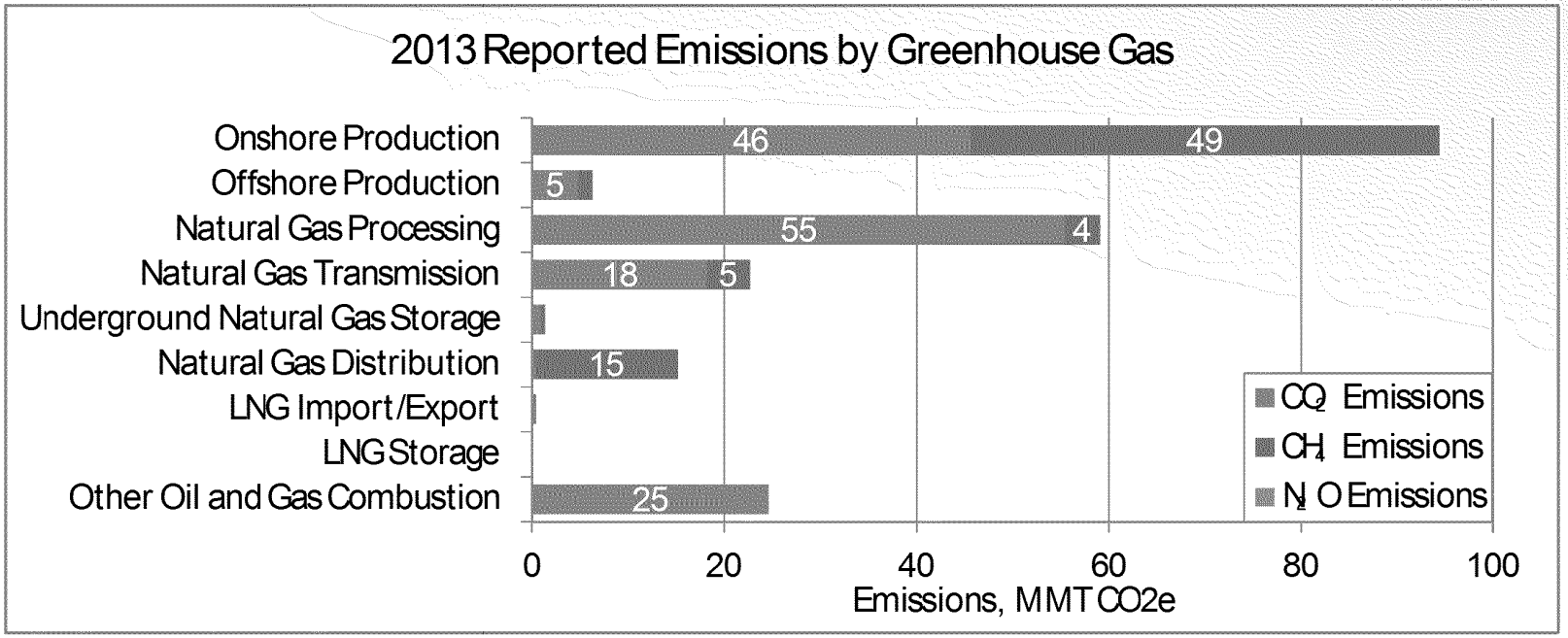
- Total reported emissions slightly increased by about 0.2 MMT CO_2e from 2011 to 2013. Reported carbon dioxide emissions increased by 10.6 MMT CO_2e and reported methane emissions decreased by 10.3 MMT CO_2e

Segment	2011 Reported Emissions (MMT CO_2e)	2012 Reported Emissions (MMT CO_2e)	2013 Reported Emissions (MMT CO_2e)	2012-13 Change in Reported Emissions (MMT CO_2e)	2011-13 Change in Reported Emissions (MMT CO_2e)
Onshore Production	92	93	95	1.5	2.2
Offshore Production	7	7	6	-0.5	-0.4
Natural Gas Processing	58	60	59	-1.5	0.2
Natural Gas Transmission	24	24	23	-0.9	-1.5
Underground Natural Gas Storage	1	1	1	-0.1	-0.2
Natural Gas Distribution	17	16	15	-0.5	-1.4
LNG Import/Export	1	1	< 1	-0.3	-0.4
LNG Storage	< 1	< 1	< 1	0.0	0.0
Other Oil and Gas Combustion	23	25	25	0.0	1.7
Total	223	226	224	-2.3	0.2

GHGRP data as of 8/18/14

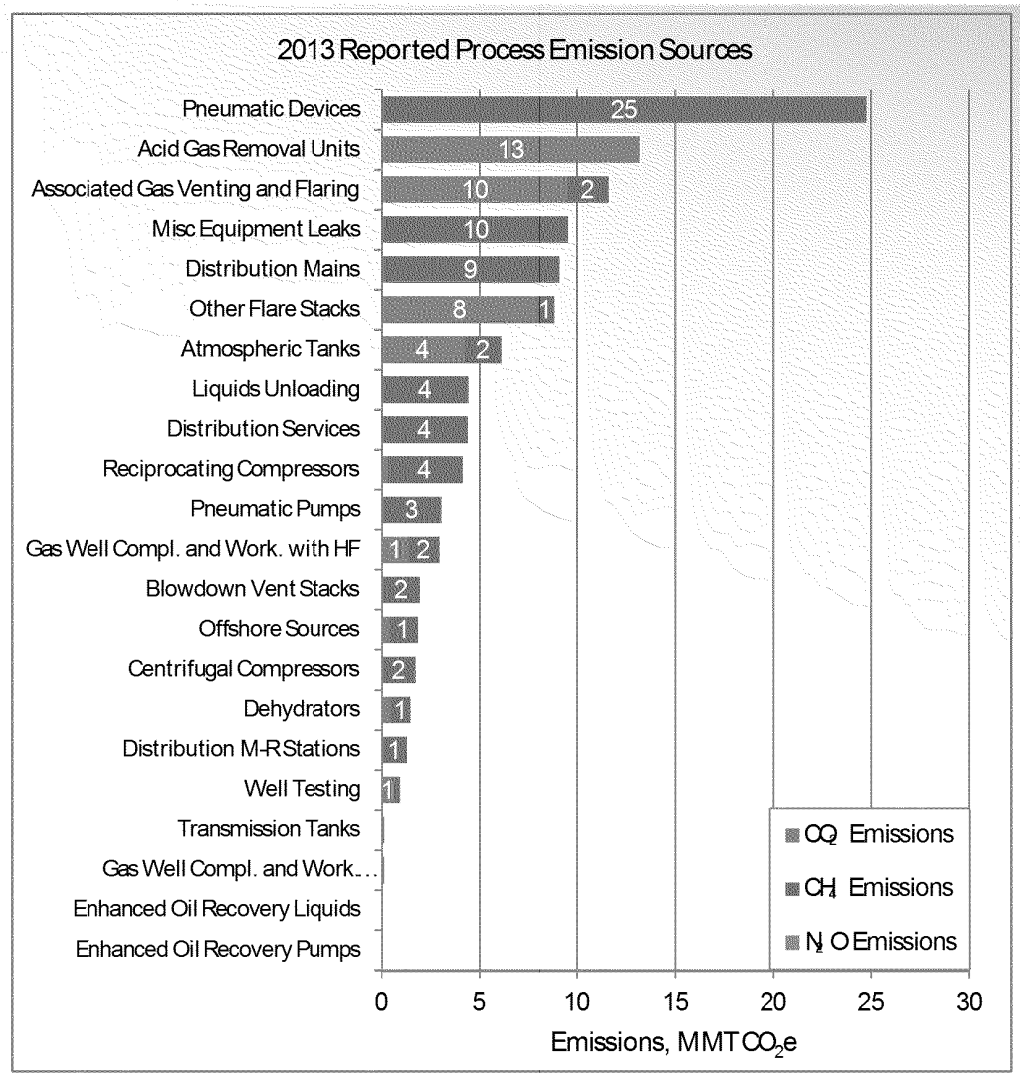
Reported Emissions by Greenhouse Gas

- Carbon dioxide (CO_2) emissions accounted for 150 MMT CO_2e and methane (CH_4) emissions accounted for 74 MMT CO_2e
- Emissions from onshore production were primarily methane while emissions from natural gas transmission, natural gas processing, and other oil and gas combustion were primarily carbon dioxide



GHGRP data as of 8/18/14

Reported Process Emission Sources



- The figure to the left shows total reported process emissions across all Petroleum and Natural Gas Systems facilities
- The largest reported process emission sources were pneumatic devices, acid gas removal units, associated gas venting and flaring, and miscellaneous equipment leaks

GHGRP data as of 8/18/14

Changes in Top Reported Sources: 2011-2013

- Increase in emissions from 2011 to 2013 not attributable to any individual source

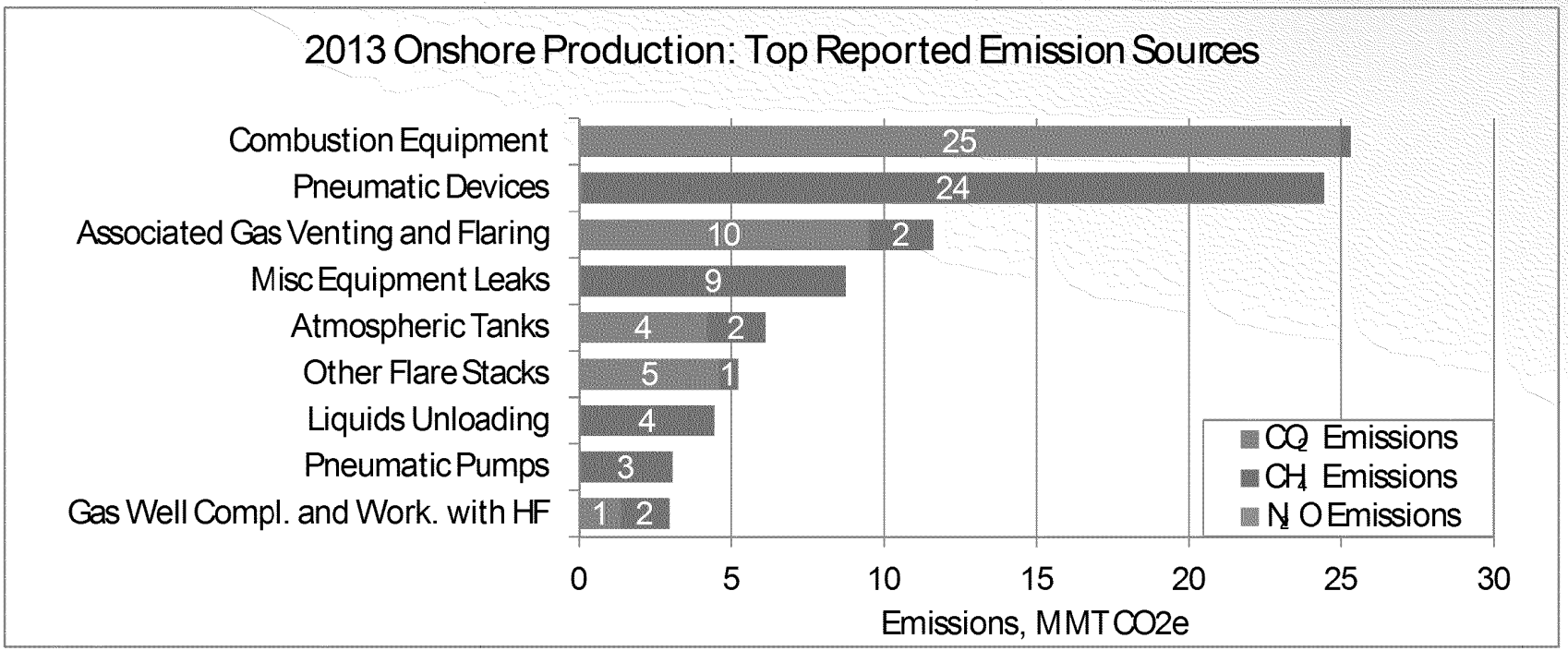
Emission Source	2011 Emissions (MMT CO_2e)	2012 Emissions (MMT CO_2e)	2013 Emissions (MMT CO_2e)	2012-13 Change in Reported Emissions (MMT CO_2e)	2011-13 Change in Reported Emissions (MMT CO_2e)
Combustion Equipment	108.8	111.4	112.4	1.0	3.6
Pneumatic Devices	21.4	22.4	24.7	2.4	3.3
Acid Gas Removal Units	15.9	15.4	13.2	-2.2	-2.7
Associated Gas Venting and Flaring	8.1	11.0	11.6	0.6	3.5
Misc Equipment Leaks	10.7	9.8	9.6	-0.3	-1.1
Distribution Mains	10.2	9.7	9.1	-0.6	-1.1
Other Flare Stacks	5.8	8.2	8.8	0.7	3.0
Atmospheric Tanks	4.2	5.6	6.1	0.5	1.9
Distribution Services	5.2	4.8	4.4	-0.4	-0.8
Liquids Unloading	7.4	6.0	4.4	-1.5	-2.9
Reciprocating Compressors	3.7	3.5	4.0	0.5	0.3
Pneumatic Pumps	3.0	3.4	3.1	-0.3	0.1
Gas Well Completions and Workovers with Hydraulic Fracturing	8.9	4.6	2.9	-1.6	-5.9
Blowdown Vent Stacks	1.5	2.4	2.0	-0.4	0.5

GHGRP data as of 8/18/14

Reported GHG Emissions by Industry Segment and Source

Onshore Production

- Reported emissions in onshore production totaled 95 MMT CO_2e
- Methane emissions totaled 49 MMT CO_2e and carbon dioxide emissions totaled 46 MMT CO_2e
- Combustion equipment (25.3 MMT CO_2e) and pneumatic devices (24.4 MMT CO_2e) were the top reported emission sources in onshore production



GHGRP data as of 8/18/14

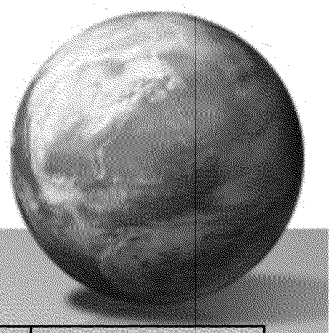
Gas Well Completions and Workovers with Hydraulic Fracturing

- 174 onshore production facilities reported emissions from gas well completions and workovers with hydraulic fracturing, which totaled 2.9 MMT CO_2e
- 40 of those facilities reported using BAMM to calculate emissions from gas well completions and workovers
- GHGRP calculation methods allow facilities to measure or estimate the backflow rate in order to report emissions using an engineering calculation, or the backflow vent or flare volume may be measured directly

Activity	Total Number	Number of RECs	Reported Venting CO_2 Emissions (MT CO_2e)	Reported Venting CH_4 Emissions (MT CO_2e)	Reported Flaring CO_2 Emissions (MT CO_2e)	Reported Flaring CH_4 Emissions (MT CO_2e)	Total Reported Emissions (MT CO_2e)
Gas Well Completions with Hydraulic Fracturing	7,053	4,961	3,976	1,367,592	1,330,722	184,495	2,887,546
Gas Well Workovers with Hydraulic Fracturing	732	312	136	36,607	10,525	1,556	48,831
Total	7,785	5,273	4,112	1,404,198	1,341,247	186,051	2,936,377

GHGRP data as of 8/18/14

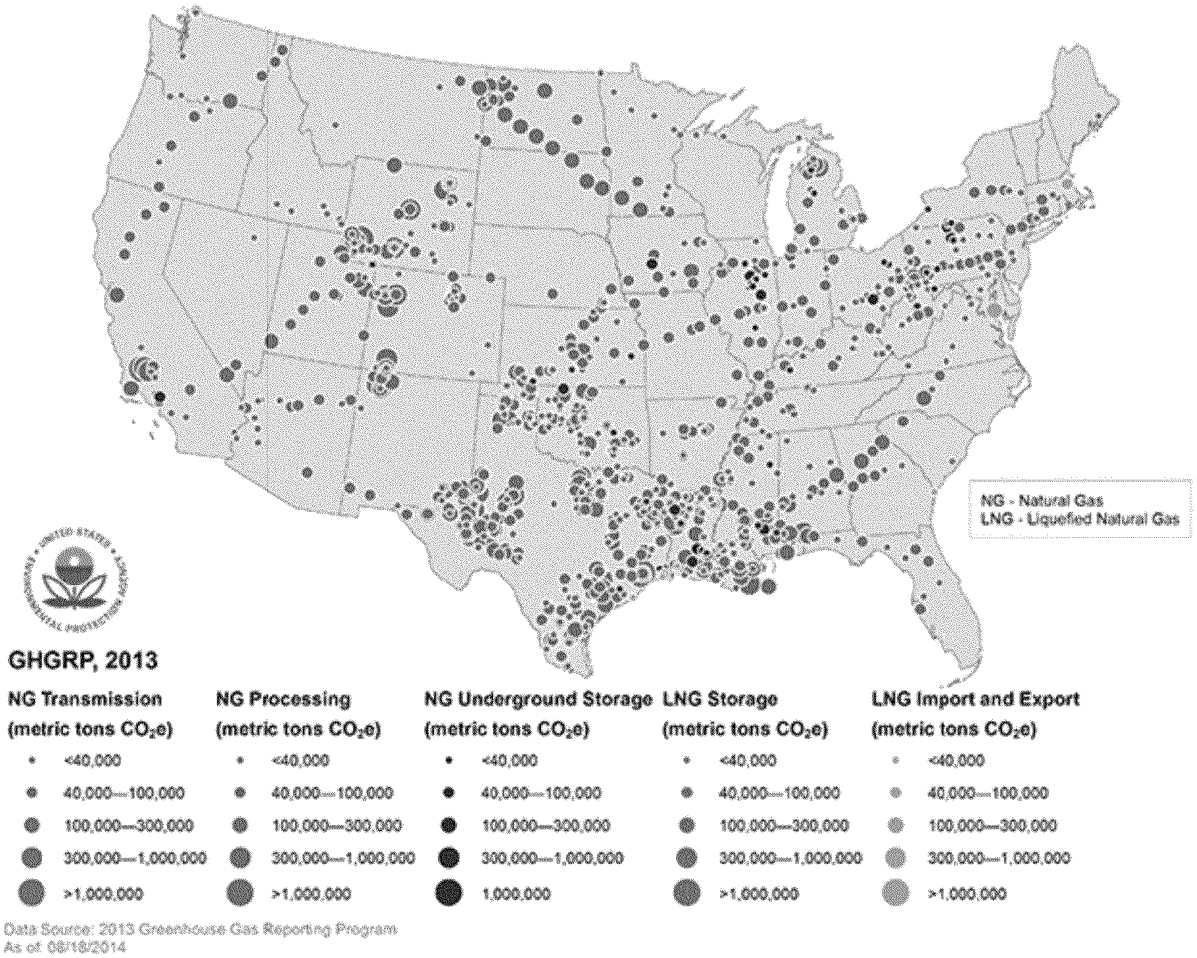
Gas Well Completions with Hydraulic Fracturing



EPA Region	State	Completion Count	Completion CO_2 Emissions (MT CO_2e)	Completion CH_4 Emissions (MT CO_2e)	Completion N_2O Emissions (MT CO_2e)	Completion Total Reported Emissions (MT CO_2e)	Completion Total Reported Emissions by EPA Region (MT CO_2e)
3	PA	1,130	588,417	895,835	351	1,484,603	1,765,703
3	WV	195	203,306	77,669	125	281,101	
4	AL	21	0	0	0	0	109,463
4	TN	10	18,973	90,478	12	109,463	
5	OH	76	127,332	18,816	69	146,217	146,217
6	AR	545	749	26,846	0	27,595	745,560
6	LA	191	2,346	11,809	5	14,160	
6	NM	164	10,808	74,076	6	84,890	
6	OK	459	32,849	74,044	13	106,905	
6	TX	2,458	302,390	209,501	118	512,009	
7	KS	18	10,621	1,269	6	11,895	11,895
8	CO	988	29,212	65,188	50	94,451	108,707
8	UT	263	2,558	4,149	2	6,708	
8	WY	535	5,138	2,406	3	7,548	

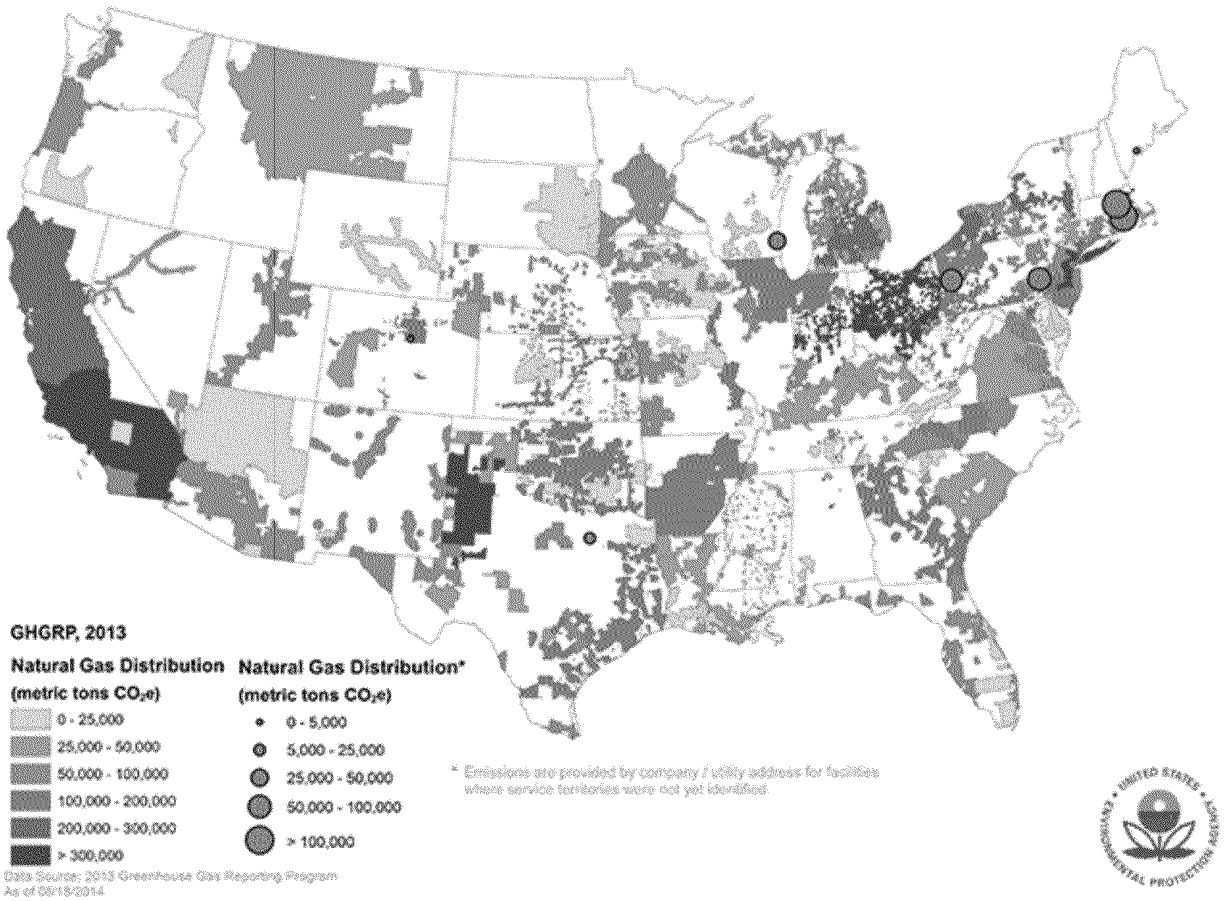
GHGRP data as of 8/18/14

NG Processing, Storage, Transmission, LNG



GHGRP data as of 8/18/14

Natural Gas Distribution



GHGRP data as of 8/18/14

GHGRP Milestones for 2014 data

Milestone	Schedule
Annual reports & deferred data reports due	March 31, 2015
EPA verification of submitted data	Spring / Summer 2015
2014 Data Publication (including deferred data)	Fall 2015

e-GGRT
Electronic Greenhouse Gas Reporting Tool

GHGRP Resources

- E-GGRT Information & Reporting Forms
  - http://www.ccdsupport.com
  - Email: GHGreporting@epa.gov
- GHG Reporting Program Information & Help
  - http://www.epa.gov/ghgreporting/index.html
  - Email: GHGReporting@epa.gov
- Subpart W Website
  - http://www.epa.gov/ghgreporting/reporters/subpart/w.html

GREENHOUSE GAS EMISSIONS REPORTING FROM THE PETROLEUM AND NATURAL GAS INDUSTRY

BACKGROUND TECHNICAL SUPPORT DOCUMENT

The Environmental Protection Agency (EPA) regulations cited in this technical support document (TSD) contain legally-binding requirements. In several chapters this TSD offers illustrative examples for complying with the minimum requirements indicated by the regulations. This is done to provide information that may be helpful for reporters' implementation efforts. Such recommendations are prefaced by the words "may" or "should" and are to be considered advisory. They are not required elements of the regulations cited in this TSD. Therefore, this document does not substitute for the regulations cited in this TSD, nor is it a regulation itself, so it does not impose legally-binding requirements on EPA or the regulated community. It may not apply to a particular situation based upon the circumstances. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

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U.S. ENVIRONMENTAL PROTECTION AGENCY
CLIMATE CHANGE DIVISION
WASHINGTON DC

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1. Segments in the Petroleum and Natural Gas Industry

The U.S. petroleum and natural gas industry encompasses the production of raw gas and crude oil from wells to the delivery of processed gas and petroleum products to consumers. These segments use energy and emit greenhouse gases (GHG). It is convenient to view the industry in the following discrete segments:

- Petroleum Industry – petroleum production, petroleum transportation, petroleum refining, petroleum storage terminals, and
- Natural Gas Industry –natural gas production, natural gas gathering and boosting (natural gas gathering and boosting are not included in this rulemaking), natural gas processing, natural gas transmission and underground storage, liquefied natural gas (LNG) import and export terminals, and natural gas distribution.

Each industry segment uses common processes and equipment in its facilities, most of which emit GHG. Each of these industry segments is described in further detail below.

a. Petroleum Industry

Petroleum Production. Petroleum or crude oil is produced from underground geologic formations. In some cases, natural gas is also produced from oil production wells; this gas is called associated natural gas. Production may require pumps or compressors for the injection of liquids or gas into the well to maintain production pressure. The produced crude oil is typically separated from water and gas, injected with chemicals, heated, and temporarily stored. GHG emissions from crude oil production result from combustion-related activities, and equipment leaks and vented emissions. Equipment counts and GHG-emitting practices are related to the number of producing crude oil wells and their production rates.

As petroleum production matures in a field, the natural reservoir pressure is not sufficient to bring the petroleum to the surface. In such cases, enhanced oil recovery (EOR) techniques are used to extract oil that otherwise can not be produced using only reservoir pressure. In the United States, there are three predominant types of EOR operations currently used; thermal EOR, gas injection EOR, and chemical injection EOR. Thermal EOR is carried out by injecting steam into the reservoir to reduce the viscosity of heavy petroleum to allow the flow of the petroleum in the reservoir and up the production well. Gas injection EOR involves injecting of gases, such as natural gas, nitrogen, or carbon dioxide (CO_2), to decrease the viscosity of the petroleum and push it towards and up the producing well. Chemical injection EOR is carried out by injecting surfactants or polymers to improve the flow of petroleum and/or enhance a water flood in the reservoir. Emissions sources from EOR operations are similar to those in conventional petroleum production fields. However, additional emissions occur when CO_2 is used for recovery. This specific EOR operation requires pumps to inject supercritical CO_2 into the reservoir while compressors maintain the recycled CO_2's supercritical state. Venting from these two emissions sources is a major source of emissions.

Petroleum Transportation. The crude oil stored at production sites is either pumped into crude oil transportation pipelines or loaded onto tankers and/or rail freight. Along the supply chain crude oil may be stored several times in tanks. These operational practices and storage tanks release mainly process GHG emissions. Emissions are related to the amount of crude oil transported and the transportation mode.

Petroleum Refining Crude oil is delivered to refineries where it is temporarily stored before being fractionated by distillation and treated. The fractions are reformed or cracked and then blended into consumer petroleum products such as gasoline, diesel, aviation fuel, kerosene, fuel oil, and asphalt. These processes are energy intensive. Equipment counts and GHG gas emitting practices are related to the number and complexity of refineries. Subpart Y of the GHG reporting rule (40 CFR Part 98) published in the Federal Register on October 30, 2009, addresses refineries and hence is not discussed further in this document.

Petroleum products are then transported via trucks, rail cars, and barges across the supply chain network to terminals and finally to end users.

b. Natural Gas Industry

Natural Gas Production In natural gas production, wells are used to withdraw raw gas from underground formations. Wells must be drilled to access the underground formations, and often require natural gas well completion procedures or other practices that vent gas from the well depending on the underground formation. The produced raw gas commonly requires treatment in the form of separation of gas/liquids, heating, chemical injection, and dehydration before being compressed and injected into gathering lines. Combustion emissions, equipment leaks, and vented emissions arise from the wells themselves, gathering pipelines, and all well-site natural gas treatment processes and related equipment and control devices. Determining emissions, equipment counts, and frequency of GHG emitting practices is related to the number of producing wellheads and the amount of produced natural gas. Further details are provided on the individual sources of GHG emissions in Appendix A.

Natural Gas Processing In the processing facility, natural gas liquids and various other constituents from the raw gas are separated, resulting in "pipeline quality" gas that is compressed and injected into the transmission pipelines. These separation processes include acid gas removal, dehydration, and fractionation. Most equipment and practices have associated GHG equipment leaks, energy consumption-related combustion GHG emissions, and/or process control related GHG vented emissions. Equipment counts and frequency of GHG emitting practices are related to the number and size of gas processing facilities. Further details are provided on the individual sources of GHG emissions in Appendix A.

Natural Gas Transmission and Storage Natural gas transmission involves high pressure, large diameter pipelines that transport natural gas from petroleum and natural gas production sites and natural gas processing facilities to natural gas distribution pipelines or large volume customers such as power plants or chemical plants. Compressor station facilities containing

large reciprocating and / or centrifugal compressors, move the gas throughout the U.S. transmission pipeline system. Equipment counts and frequency of GHG emitting practices are related to the number and size of compressor stations and the length of transmission pipelines.

Natural gas is also injected and stored in underground formations, or stored as LNG in above ground storage tanks during periods of low demand (e.g., spring or fall), and then withdrawn, processed, and distributed during periods of high demand (e.g., winter and summer). Compressors, pumps, and dehydrators are the primary contributors to emissions from these underground and LNG storage facilities. Equipment counts and GHG emitting practices are related to the number of storage stations.

Imported and exported LNG also requires transportation and storage. These processes are similar to LNG storage and require compression and cooling processes. GHG emissions in this segment are related to the number of LNG import and export terminals and LNG storage facilities. Further details are provided on the individual sources of GHG emissions for all of transmission and storage in Appendix A.

Natural Gas Distribution Natural gas distribution pipelines take high-pressure gas from the transmission pipelines at "city gate" stations, reduce and regulate the pressure, and distribute the gas through primarily underground mains and service lines to individual end users. There are also underground regulating vaults between distribution mains and service lines. GHG emissions from distribution systems are related to the pipelines, regulating stations and vaults, and customer/residential meters. Equipment counts and GHG emitting practices can be related to the number of regulating stations and the length of pipelines. Further details are provided on the individual sources of GHG emissions in Appendix A.

2. Types of Emissions Sources and GHGs

The three main GHGs that are relevant to the petroleum and natural gas industry are methane (CH_4), carbon dioxide CO_2, and nitrous oxide (N_2O). All three gases were taken into account when developing the threshold analysis.

Emissions from sources in the petroleum and gas industry can be classified into one of two types:

Combustion-related emissions

Combustion-related emissions result from the use of petroleum-derived fuels and natural gas as fuel in equipment (e.g., heaters, engines, furnaces, etc.) in the petroleum and gas industry. CO_2 is the predominant combustion-related emission; however, because combustion equipment is less than 100 percent efficient, CH_4 and other unburned hydrocarbons are emitted. N_2O results from both fuel-bound nitrogen and nitrogen from atmospheric air. For methodologies to quantify GHG emissions from combustion, please refer to Subpart C of the GHG reporting rule

(40 CFR Part 98), except for GHG emissions from flaring, onshore production stationary and portable combustion GHG emissions, and combustion emissions from stationary equipment involved in natural gas distribution. For methodologies to quantify combustion emissions from flaring, onshore production stationary and portable equipment, and combustion emissions from stationary equipment involved in natural gas distribution, please refer to Subpart W.

Equipment leaks and vented emissions

The Intergovernmental Panel on Climate Change (IPCC) and the Inventory of U.S. GHG Emissions and Sinks[1] (henceforth referred to as the U.S. GHG Inventory) define fugitive emissions to be both intentional and unintentional emissions from systems that extract, process, and deliver fossil fuels. Intentional emissions are emissions designed into the equipment or system. For example, reciprocating compressor rod packing has a certain level of emissions by design, e.g., there is a clearance provided between the packing and the compressor rod for free movement of the rod that results in emissions. Also, by design, vent stacks in petroleum and natural gas production, natural gas processing, and petroleum refining facilities release natural gas to the atmosphere. Unintentional emissions result from wear and tear or damage to the equipment. For example, valves result in emissions due to wear and tear from continuous use over a period of time. Also, pipelines damaged during maintenance operations or corrosion result in unintentional emissions.

IPCC's definition is not intuitive since fugitive in itself means unintentional. Therefore, this document henceforth distinguishes between fugitive emissions (referred to as equipment leaks in the final subpart W) and vented emissions.

Equipment leaks are those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Vented emissions are intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

3. GHG Emissions from the Petroleum and Natural Gas Industry

The U.S. GHG Inventory provides estimates of equipment leaks and vented CH_4 and CO_2 emissions from all segments of the petroleum and natural gas industry. These estimates are based mostly on emissions factors available from two major studies conducted by EPA/Gas

[1] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006, (April 2008), USEPA #430-R-08-005

Research Institute (EPA/GRI)[2] for the natural gas segment and EPA/Radian[3] for the petroleum segment. These studies were conducted in the early and late 1990s respectively.

Petroleum Segment

According to the 2006 U.S. GHG Inventory, EPA estimates that crude oil production operations accounted for over 97 percent of total CH_4 emissions from the petroleum industry. Crude oil transportation activities accounted for less than one half of a percent of total CH_4 emissions from the oil industry. Crude oil refining processes accounted for slightly over two percent of total CH_4 emissions from the petroleum industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the petroleum refineries. The 2006 U.S. GHG Inventory for Petroleum Systems currently estimates CO_2 emissions from only crude oil production operations. Research is underway to include other larger sources of CO_2 emissions in future inventories.

Natural Gas Segment

Emissions from natural gas production accounted for approximately 66 percent of CH_4 emissions and about 25 percent of non-energy CO_2 emissions from the natural gas industry in 2006. Processing facilities accounted for about 6 percent of CH_4 emissions and approximately 74 percent of non-energy CO_2 emissions from the natural gas industry. CH_4 emissions from the natural gas transmission and storage segment accounted for approximately 17 percent of emissions, while CO_2 emissions from natural gas transmission and storage accounted for less than one percent of the non-energy CO_2 emissions from the natural gas industry. Natural gas distribution segment emissions, which account for approximately 10 percent of CH_4 emissions from natural gas systems and less than one percent of non-energy CO_2 emissions, result mainly from equipment leaks from gate stations and pipelines.

Updates to Certain Emissions Sources

The EPA/GRI study used the best available data and somewhat restricted knowledge of industry practices at the time to provide estimates of emissions from each source in the various segments of the natural gas industry. In addition, this study was conducted at a time when CH_4 emissions were not a significant concern in the discussion about GHG emissions. Over the years, new data and increased knowledge of industry operations and practices have highlighted the fact that emissions estimates from the EPA/GRI study are outdated and potentially understated for some emissions sources. The following emissions sources are believed to be significantly underestimated in the U.S. GHG Inventory: well venting for liquids unloading; gas well venting during well completions; gas well venting during well workovers; crude oil and condensate storage tanks; centrifugal compressor wet seal degassing venting; scrubber dump valves; onshore combustion; and flaring.

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[2] EPA/GRI (1996) *Methane Emissions from the Natural Gas Industry*. Prepared by Harrison, M., T. Shires, J. Wessels, and R. Cowgill, eds., Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC. EPA-600/R-96-080a.

[3] EPA (1996) *Methane Emissions from the U.S. Petroleum Industry (Draft)*. Prepared by Radian. U.S. Environmental Protection Agency. June 1996.

The understatement of emissions in the U.S. GHG Inventory were revised using publicly available information for all sources and included in the analysis, except crude oil and condensate storage tanks and flares, and scrubber dump valves.[4] The revised estimates for storage tanks are available in "Analysis of Tank Emissions", found in the EPA-HQ-OAR-2009-0923-0002 docket, but the revised emissions have not been included in this analysis (See Appendix C for further details). For further discussion on the inclusion of scrubber dump valves in this rulemaking please see the analysis "Scrubber Dump Valves" in EPA-HQ-OAR-2009-0923 docket. EPA has limited publicly available information to accurately revise estimates on a national level for flaring and scrubber dump valves. For onshore combustion emissions, EPA used emissions estimates from the GHG inventory which are based on EIA data which EPA believes to be underestimated. Refer to section 4(c)(iii) of the TSD for further details. This is explained further below. Appendix B provides a detailed discussion on how new estimates were developed for each of the four underestimated sources. Table 1 provides a comparison of emissions factors as available from the EPA/GRI study and as revised in this document. Table 2 provides a comparison of emissions from each segment of the natural gas industry as available in the U.S. GHG Inventory and as calculated based on the revised estimates for the four underestimated sources.

Table 1: Comparison of Emissions Factors from Four Updated Emissions Sources

Emissions Source Name	EPA/GRI Emissions Factor	Revised Emissions Factor	Units
1) Well venting for liquids unloading	1.02	11	CH_4 – metric tons/year-well
2) Gas well venting during completions			
Conventional well completions	0.02	0.71	CH_4 – metric tons/year-completion
Unconventional well completions	0.02	177	CH_4 – metric tons/year-completion
3) Gas well venting during well workovers			
Conventional well workovers	0.05	0.05	CH_4 – metric tons/year-workover
Unconventional well workovers	0.05	177	CH_4 – metric tons/year-workover
4) Centrifugal compressor wet seal degassing venting	0	233	CH_4 – metric tons/year-compressor

1. Conversion factor: 0.01926 metric tons = 1 Mcf

[4] EPA did consider the data available from two new studies, TCEQ (2009) and TERC (2009). However, it was found that the data available from the two studies raise several questions regarding the magnitude of emissions from tanks and hence were not found appropriate for any further analysis until the issues are satisfactorily understood and/ or resolved by the authors and covered parties.

Table 2: Comparison of Process Emissions from each Segment of the Natural Gas and Petroleum Industries

Segment Name	U.S. GHG Inventory[1] Estimate for Year 2006 ($MMTCO_2e$)	Revised Estimate for Year 2006 ($MMTCO_2e$)
Production[2]	90.2	198.0
Processing	35.9	39.5
Transmission and Storage	48.4	52.6
Distribution	27.3	27.3

1. U.S. EPA (2008) *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006.*

2. *Production includes equipment leaks and vented emissions from both the natural gas and petroleum sectors' onshore and offshore facilities.*

After revising the U.S. GHG Inventory emissions estimates for the sources listed in Table 1, total equipment leak and vented CH_4 and CO_2 emissions from the petroleum and natural gas industry were 317 million metric tons of CO_2 equivalent ($MMTCO_2e$) in 2006. Of this total, the natural gas industry emitted 261 $MMTCO_2e$ of CH_4 and 28.50 $MMTCO_2e$ of CO_2 in 2006. Total CH_4 and CO_2 emissions from the petroleum industry in 2006 were 27.74 $MMTCO_2e$ and 0.29 $MMTCO_2e$ respectively.

4. Methodology for Selection of Industry Segments and Emissions Sources Feasible for Inclusion in a GHG Reporting Rule

It is important to develop criteria to help identify GHG emissions sources in the petroleum and natural gas industry most likely to be of interest to policymakers. To identify sources for inclusion in a GHG reporting rule, two preliminary steps were taken; 1) review existing regulations to identify emissions sources already being regulated, and 2) review existing programs and guidance documents to identify a comprehensive list of emissions sources for potential inclusion in the proposed rule.

The first step in determining emissions sources to be included in a GHG reporting rule was to review existing regulations that the industry is subject to. Reviewing existing reporting requirements highlighted those sources that are currently subject to regulation for other pollutants and may be good candidates for addressing GHG emissions. The second step was to establish a comprehensive list of emissions sources from the various existing programs and guidance documents on GHG emissions reporting. This provided an exhaustive list of emissions sources for the purposes of this analysis and avoided the exclusion of any emissions sources already being monitored for reporting under other program(s). Both of these steps are described below.

a. Review of Existing Regulations

The first step was to understand existing regulations and consider adapting elements of the existing regulations to a reporting rule for GHG emissions. When the Mandatory Reporting Rule development process began, there were three emissions reporting regulations and six emissions reduction regulations in place for the petroleum and natural gas industry, including one voluntary reporting program included in the Code of Federal Regulations. This table also includes EPA's final GHG reporting rule, which requires certain petroleum and gas facilities to report their combustion-related emissions. Table 3 provides a summary of each of these nine reporting and reduction regulations.

Table 3: Summary of Regulations Related to the Petroleum and Natural Gas Industry

Regulation	Type	Point/ Area/ Major/ Mobile Source	Gases Covered	Segment and Sources
EPA 40 CFR Part 98 Final Rule: Mandatory Reporting of Greenhouse Gases	Mandatory Emissions Reporting	Point, Area, Biogenic	CO_2, CH_4, N_2O, HFCs, PFCs, , SF_6, NF_3, and HFE	Annual reporting of GHG emissions from direct emitters (including petroleum and natural gas systems) and suppliers of industrial GHGs in the United States.
EPA 40 CFR Part 51 – Consolidated Emissions Reporting	Emissions Reporting	Point, Area, Mobile,	VOCs, NOx, CO, NH_3, PM_{10}, $PM_{2.5}$	All segments of the petroleum and natural gas industry
DOE 10 CFR Part 300 – Voluntary GHG Reporting	Voluntary GHG Reporting	Point, Area, Mobile	CO_2, CH_4, N_2O, HFCs, PFCs, , SF_6, and CFCs	All segments of the petroleum and natural gas industry
EPA 40 CFR Part 60, Subpart KKK	NSPS[2]	Point	VOCs	Onshore processing plants; sources include compressor stations, dehydration units, sweetening units, underground storage tanks, field gas gathering systems, or liquefied natural gas units located in the plant
EPA 40 CFR Part 60, Subpart LLL	NSPS[2]	Point	SO_2	Onshore processing plants; Sweetening units, and sweetening units followed by a sulfur recovery unit
EPA 40 CFR Part 63, NESHAP[1], Subpart HHH	MACT[3]	Point (Glycol dehydrators, natural gas transmission and storage facilities)	HAPs	Glycol dehydrators

EPA 40 CFR Part 63, NESHAP[1], Subpart HH	MACT[3]	Major and Area (petroleum and natural gas production, up to and including processing plants)	HAPs	Point Source - Glycol dehydrators and tanks in petroleum and natural gas production; equipment leaks at gas processing plants Area Source - Triethylene glycol (TEG) dehydrators in petroleum and natural gas production
EPA 40 CFR Part 63, NESHAP[1], –Subpart YYYY	MACT[3]	Major and Area (Stationary Combustion Turbine)	HAPs	All segments of the petroleum and natural gas industry
EPA 40 CFR Part 63, NESHAP[1], Subpart ZZZZ	MACT[3]	Major and Area (Reciprocating Internal Combustion Engines)	HAPs	All segments of the petroleum and natural gas industry
Notes: [1]National Emission Standards for Hazardous Air Pollutants [2]New Source Performance Standard [3]Maximum Allowable Control Technology				

Table 3, indicates that only DOE 10 CFR Part 300 includes the monitoring or reporting of CH_4 emissions from the petroleum and natural gas industry. However, this program is a voluntary reporting program and is not expected to have a comprehensive coverage of CH_4 emissions. Although some of the sources included in the other regulations lead to CH_4 emissions, these emissions are not reported. The MACT regulated sources are subject to Part 70 permits which require the reporting of all major HAP emission sources, but not GHGs. GHG emissions from petroleum and natural gas operations are not systematically monitored and reported; therefore these regulations and programs cannot serve as the foundation for a GHG emissions reporting rule.

b. Review of Existing Programs and Studies

The second step was to review existing monitoring and reporting programs to identify all emissions sources that are already monitored under these programs. When the Mandatory Reporting Rule development process began, six reporting programs and six guidance documents were reviewed. Table 4 summarizes this review, highlighting monitoring points identified by the programs and guidance documents.

Table 4 shows that the different monitoring programs and guidance documents reflect the points of monitoring identified in the U.S. GHG Inventory, which are consistent with the range of sources covered in the 2006 IPCC Guidelines. Therefore, the U.S. GHG Inventory was used to provide the initial list of emissions sources for determining the emissions sources that can be potentially included in the rule.

The preliminary review provided a potential list of sources, but did not yield any definitive indication on the emissions sources that were most suitable for potential inclusion in a reporting program. A systematic assessment of emissions sources in the petroleum and

natural gas industry was then undertaken to identify the specific emissions sources (e.g., equipment or component) for inclusion in a GHG reporting rule.

Table 4: Summary of Program and Guidance Documents on GHG Emissions Monitoring and Reporting

Reporting Program/Guidance	Source Category (or Fuel)	Coverage (Gases or Fuels)	Points of Monitoring	Monitoring Methods and/or GHG Calculation Methods*
2006 IPCC Guidelines for National GHG Inventory, Volume 2, Chapter 4	Petroleum and Gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	Oil and natural gas systems fugitive equipment leaks, evaporation losses, venting, flaring, and accidental releases; and all other fugitive emissions at oil and natural gas production, transportation, processing, refining, and distribution facilities from equipment leaks, storage losses, pipeline breaks, well blowouts, land farms, gas migration to the surface around the outside of wellhead casing, surface casing vent bows, biogenic gas formation from tailings ponds and any other gas or vapor releases not specifically accounted for as venting or flaring	Accounting/ reporting methodologies and guidelines Companies choose a base year for which verifiable emissions data are available. The base year emissions are used as an historic control against which the company's emissions are tracked over time. This ensures data consistency over time. Direct measurement of GHG emissions by monitoring concentration and flow rate can also be conducted. IPCC methodologies are broken down into the following categories: - Tier I calculation-based methodologies for estimating emissions involve the calculation of emissions based on activity data and default industry segment emission factors - Tier II calculation-based methodologies for estimating emissions involve the calculation of emissions based on activity data and country-specific industry segment emission factors or by performing a mass balance using country-specific oil and/or gas production information Tier III calculation-based methodologies for estimating emissions involve "rigorous bottom-up assessment by primary type of source (e.g. evaporation losses, equipment leaks) at the individual facility level with appropriate accounting of contributions from temporary and minor field or well-site installations. The calculation of emissions is based on activity data and facility-specific emission factors
AGA - Greenhouse Gas Emissions Estimation Methodologies, Procedures, and Guidelines	Gas – Distribution	CH_4, non-combustion CO_2 and other GHG gases	Segment-level counts, equipment discharges (i.e. valves, open-ended lines, vent stacks), and segment	Equipment or segment emissions rates and engineering calculations Tier I, II (IPCC) - facility level emissions rates

for the Natural Gas Distribution Sector			capacities, facility counts and capacities	Tier III (IPCC) - equipment emissions rates for intentional emissions, process level emissions rates, and process/equipment level emissions rate
API - Compendium of GHG Emissions Estimation Methodologies for the Oil and Gas Industry	Gas and Petroleum – all segments	CH_4, non-combustion CO_2	Equipment discharges (e.g. valves, open-ended lines, vent stacks), vent stacks for equipment types, tank PRV/vents, and facility input	Equipment or segment emissions rates and engineering calculations Tier II (IPCC) - facility level emissions rates Tier III (IPCC) - equipment emissions rates for intentional emissions, process level emissions rates, tank level emissions rates, and process/equipment level emissions rate (BY SEGMENT)
California Climate Action Registry General Reporting Protocol, March 2007	All legal entities (e.g. corporations, institutions, and organizations) registered in California, including petroleum and gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in indirect and direct emission of GHG gases for the entity	Provides references for use in making fugitive calculations The CCAR does not specify methodology to calculate fugitive emissions
California Mandatory GHG Reporting Program	Petroleum – Refineries	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in CH_4 and CO_2 fugitive emissions for petroleum refineries	Continuous monitoring methodologies and equipment or process emissions rates CO_2 process emissions can be determined by continuous emissions monitoring systems. Methods for calculating fugitive emissions and emissions from flares and other control devices are also available
DOE Voluntary Reporting of Greenhouse Gases Program (1605(b))	Petroleum and Gas- All Segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in direct and indirect emissions of GHG gases for the corporation or organization	Direct, site-specific measurements of emissions or all mass balance factors Mass-balance approach, using measured activity data and emission factors that are publicly documented and widely reviewed and adopted by a public agency, a standards-setting organization or an industry group Mass-balance approach, using measured activity data and other emission factors

				Mass balance approach using estimated activity data and default emissions factors.
EU ETS 1st and 2nd Reporting Period	Petroleum – Refining	Non-combustion CO_2	Hydrogen production	Engineering calculations Operators may calculate emissions using a mass-balance approach
INGAA - GHG Emissions Estimation Guidelines for Natural Gas Transmission and Storage, Volume 1	Gas - Transmission/Storage	CH_4, non-combustion CO_2	Segment-level counts, equipment discharges (i.e. valves, open-ended lines, vent stacks), and segment capacities, facility counts and capacities	Equipment or segment emissions rates Tier I (IPCC)- segment level emissions rates from intentional and unintentional releases Tier II - equipment level emissions rates for intentional releases Tier II (IPCC) – facility and equipment level emissions rates for unintentional leaks Engineering calculation methodologies for: - Pig traps - Overhauls - Flaring
IPIECA - Petroleum Industry Guidelines for Reporting GHG Emissions	Petroleum and Gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	Refers to API Compendium points of monitoring: Equipment discharges (e.g. valves, open-ended lines, vent stacks), vent stacks for equipment types, tank PRV/vents, and facility input	Tiers I, II, and III (IPCC) definitions and reporting methods for all fugitive and vented GHG emissions in the oil and gas industry
New Mexico GHG Mandatory Emissions Inventory	Petroleum refineries	CO_2 reporting starts 2008 , CH_4 reporting starts 2010	Equipment discharges (e.g. valves, pump seals, connectors, and flanges)	- 2009 reporting procedures will be made available in 10/2008

The Climate Registry (General Reporting Protocol for the Voluntary Reporting Program), 2007	All legal entities (e.g. corporations, institutions, and organizations) including petroleum and gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in emission of GHG gases for the entity	Continuous monitoring methodologies and equipment or process emissions rates Measurement-based methodology monitor gas flow (continuous, flow meter) and test methane concentration in the flue gas. Calculation-based methodologies involve the calculation of emissions based on activity data and emission factors
Western Regional Air Partnership (WRAP)	Petroleum and Gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in emission of GHG gases for the entity	Provides quantification methods for all sources from all sectors of the petroleum and gas industry considered in the rule. Quantification methods are typically engineering equation; however, parameters for the equations in several cases require measurement of flow rates, such as from well venting
World Resources Institute/ World Business Council for Sustainable Development GHG Protocol Corporate Standard, Revised Edition 2003	Organizations with operations that result in GHG (GHG) emissions e.g. corporations (primarily), universities, NGOs, and government agencies. This includes the oil and gas industry	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in direct and indirect emission of GHG gases for the corporation or organization	Provides continuous monitoring methodologies and equipment or process emissions rates Companies need to choose a base year for which verifiable emissions data are available and specify their reasons for choosing the year. "The base year emissions are used as an historic datum against which the company's emissions are tracked over time. Emissions in the base year should be recalculated to reflect a change in the structure of the company, or to reflect a change in the accounting methodology used. This ensures data consistency over time." Direct measurement of GHG emissions by monitoring concentration and flow rate can be conducted. Calculation-based methodologies for estimating emissions involve the calculation of emissions based on activity data and emission factors

i. EPA 2007 Cooperative Agreement with University of Texas (UT) Austin to Update GRI/ EPA Study Estimated Emission Factors

In the past decade, there has been growing interest in better understanding CH_4 emissions sources from the petroleum and natural gas industry. As mentioned above, the seminal study, upon which much of the current knowledge on CH_4 emission factors is based, is *Methane Emissions from the Natural Gas Industry (GRI/EPA 1996).* In the United States, the GRI/EPA Study serves as the basis for most CH_4 estimates from natural gas systems in EPA's *Inventory of U.S. GHG Emissions and Sinks*, EPA's Natural Gas STAR Program, Methane to Markets International Program, State Inventories, the American Petroleum Institute (API) Compendium, a transmission and distribution protocol by the Interstate Natural Gas Association of America (INGAA), as well as all of the organizations that reference these documents and programs in their individual work. The GRI/EPA Study was also evaluated for its relevance for a separate effort to develop a transmission and distribution GHG accounting protocol by the California Climate Action Registry. Internationally, the GRI/EPA Study is the source for many of the emission factors included in the Intergovernmental Panel on Climate Change Guidelines for National Greenhouse Gas Inventories.

Although the GRI/EPA Study has been the cornerstone for estimating CH_4 emissions from the natural gas industry to date, the data on which the study is based are now over a decade and a half old and in some cases (e.g., wells, compressors), not always reflective of current conditions in the United States. In recognition of the fact that existing methane emission factors were becoming quickly outdated, in 2007 EPA funded a 4-year cooperative agreement with UT Austin to support research and, as appropriate, measurement studies to update selected CH_4 emission factors from the 1996 GRI study. The cooperative agreement identified a small set of 11 priority sources in different industry segments on which to focus emission factor development. With the limited budget available, as of mid-2010, the project has begun work on updating emission factors for reciprocating and centrifugal compressors only. Specifically, the project team has initiated preliminary measurement studies at compressor stations at natural gas transmission and storage facilities owned by two companies. Now approaching its final year, the project team is currently evaluating the most efficient use of the remaining resources; specifically whether to undertake additional measurements on transmission and storage facilities to gain the most robust data set possible, or to use remaining funds on another source of emissions in the production, processing, transmission, or distribution segments.

The UT Austin cooperative agreement was initiated to develop representative national emission factors- it was not designed, like the GHG reporting rule, to comprehensively collect actual GHG emissions data to support a range of future climate policies. To meet the goals of the reporting rule, for larger sources, such as compressors, it is critical that EPA collect actual emissions data in order to understand trends and also connect emissions to specific equipment and types of operations. For example, if there is a trend regarding the maintenance of rod packing over time, this information would not be obtained through a static data set based on national compressor-level emission factors. .

Further, the limited budget available for the UT Austin study will not allow for emissions information from a large number of sources; the GHG reporting rule will be collecting comprehensive actual emissions data and other relevant information from major sources across the United States petroleum and natural gas industry for all U.S. facilities over 25,000 mtCO2e. In addition, the GHG reporting rule will collect applicable information (e.g., equipment component counts and operational data) needed to verify the reported GHG data and support future climate policy analysis.

c. Selection of Emissions Sources for Reporting

When identifying emissions sources for inclusion in a GHG reporting rule, two questions need addressing. The first is defining a facility. In other words, what physically constitutes a facility? The second is determining which sources of emissions should a facility report? Including or excluding sources from a GHG reporting rule without knowing the definition of a facility is difficult. Therefore, both the facility definition and emissions source inclusion (or exclusion) were reviewed to arrive at a conclusion.

i. Facility Definition Characterization

Typically, the various regulations under the Clean Air Act (CAA) define a facility as a group of emissions sources all located in a contiguous area and under the common control of the same person (or persons). This definition can be easily applied to offshore petroleum and natural production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, and LNG import and export equipment since the operations are all located in a clearly defined boundary. However, as discussed further below, this definition does not as directly lend itself to all industry segments, such as onshore petroleum and natural gas production, natural gas distribution, and petroleum transportation sectors.

Onshore petroleum and natural gas production operations can be very diverse in arrangement. Sometimes crude oil and natural gas producing wellheads are far apart with individual equipment at each wellhead. Alternatively, several wells in close proximity may be connected to common pieces of equipment. Whether wells are connected to common equipment or individual equipment depends on factors such as distance between wells, production rate, and ownership and royalty payment. New well drilling techniques such as horizontal and directional drilling allow for multiple wellheads to be located at a single location (or pad) from where they are drilled to connect to different zones in the same reservoir. Therefore, the conventional facility definition of a "contiguous area" under a common owner/ operator cannot be easily applied to the onshore petroleum and natural gas production industry segment. Refer to Section 4(c)(iv) in the TSD for a more detailed discussion of the facility definition for onshore petroleum and natural gas production.

An alternative to a physical facility definition is the use of a corporate level reporter definition. In such a case the corporation that owns or operates petroleum and natural gas production operations could be required to report. Here the threshold for reporting could require that an individual corporation sum up GHG emissions from all the fields it is

operating in and determine if its total emissions surpass the threshold. See Appendix D for further discussion of this issue.

In the natural gas distribution segment the meters and regulators in the distribution segment are primarily located at small stations or underground vaults distributed over large urban or suburban regions. Individually defining each station or vault as a facility is impractical owing to the size and expected magnitude of emissions from single stations. However, a logical grouping of distribution equipment exists at the regulated local distribution company level. The precedent for reporting at this type of facility already exists under the Pipeline and Hazardous Materials Safety Administration (PHMSA) requirements under CFR Title 49 Section 191.11. Refer to Section 4(c)(iv) of the TSD for a more detailed discussion of the definition for natural gas distribution. As explained in the Response to Comments, the PHMSA regulations primarily relate to pipeline safety provisions, and are unrelated to information EPA seeks to collect under this rule.

ii. Selection of Potential Emissions Sources for Reporting

Given that there are over 100 emissions sources[1] in the petroleum and natural gas industry, it is important to target sources which contribute significantly to the total national emissions for the industry. This avoids an excessive reporting burden on the industry, but at the same time enables maximum coverage for emissions reporting. The selection of emissions sources for potential inclusion in the proposed rulemaking was conducted in three steps.

Step 1: Characterize Emissions Sources

The U.S. GHG Inventory was used as the complete list of sources under consideration for inclusion in a reporting rule. The U.S. GHG Inventory was also used to provide all relevant emissions source characteristics such as type, number of sources across industry segments, geographic location, emissions per unit of output, total national emissions from each emissions source, and frequency of emissions. Also, information included in the U.S. GHG Inventory and the Natural Gas STAR Program technical studies were used to identify the different monitoring methods that are considered the best for each emissions source. If there are several monitoring methods for the same source, with equivalent capabilities, then the one with lower economic burden was considered in the analysis.

Step 2: Identify Selection Criteria and Develop Decision Tree for Selection

There are several factors that impact the decision on whether an emissions source should be included for reporting. A discussion of the factors follows below.

- *Significant Contribution to U.S. GHG Inventory* – Emissions sources that contribute significant emissions can be considered for potential inclusion in the rule, since they increase the coverage of emissions reporting. Typically, in petroleum and natural gas facilities, 80 percent or more of the facility emissions are reported to be from approximately 10 percent of the emissions sources. This is a good benchmark to ensure the adequate coverage of emissions while reducing the number of emissions sources required for reporting thus, keeping the reporting burden to a minimum. Emissions sources in each segment of the natural gas and petroleum industry can be sorted into two

main categories: (1) top sources contributing to 80 percent of the emissions from the segment, and (2) the remaining sources contributing to the remaining 20 percent of the emissions from that particular segment. This can be easily achieved by determining the emissions contribution of each emissions source to the segment it belongs to, listing the emissions sources in a descending order, and identifying all the sources at the top that contribute to 80 percent of the emissions. Appendix A provides a listing of all emissions sources in the U.S. GHG Inventory and a breakdown of the top emissions sources by industry segment.

- *Type of Emissions* – The magnitude of emissions per unit or piece of equipment typically depends on the type of emissions. Vented emissions per unit source are usually much higher than equipment leak emissions from a unit source. For example, emissions from compressor blowdown venting for one compressor are much higher than equipment leak emissions from any one unit component source on the compressor. The burden from covering emissions reporting from each unit source (i.e. dollar per ton of emissions reported) is typically much lower in the case of venting sources in comparison to equipment leak emission sources when the same monitoring method is used. Therefore, vented sources could be treated separately from equipment leak sources for assessment of monitoring requirements.

- *Best Practice Monitoring Method(s)* – Depending on the types of monitoring methods typically used, a source may or may not be a potential for emissions reporting. There are four types of monitoring methods as follows:

    - Continuous monitoring – refers to cases where technologies are available that continuously monitor either the emissions from a source or a related parameter that can be used in estimating emissions. For example, continuous monitoring meters can determine the flow rate and in line analyzers can determine the composition of emissions from a process vent.
    - Periodic monitoring – refers to monitoring at periodic intervals to determine emissions from sources. For example, leak detection and measurement equipment can be used on a recurring basis to identify and measure an emissions rate from equipment.
    - Engineering calculations – refers to estimation of emissions using engineering parameters. For example, emissions from a vessel emergency release can be estimated by calculating the volume of the emitting vessel.
    - Emissions factors – refers to utilizing an existing emissions rate for a given source and multiplying it by the relevant activity data to estimate emissions. For example, emissions per equipment unit per year can be multiplied by the number of pieces of equipment in a facility to estimate annual emissions from that equipment for the facility.

- *Accessibility of emissions sources* – Not all emissions sources are directly accessible physically for emissions detection and/or measurement. For example, connectors on pipelines, pressure relief valves on equipment, and vents on storage tanks may be out of direct physical reach and could require the use of bucket trucks or scaffolding to access

them. In such cases requiring emissions detection and measurement may not always be feasible such as with leak detection equipment that requires the operator to be in close physical proximity to the equipment. Also, such requirements could pose health and safety hazards or lead to large cost burden. The accessibility of emissions sources was considered when addressing monitoring requirements and determining the type of leak detection equipment allowed under Subpart W.

- *Geographical dispersion of emissions sources* – The cost burden for detecting and measuring emissions will largely depend on the distance between various sources. Monitoring methods will have to be chosen considering the dispersion of emissions sources.

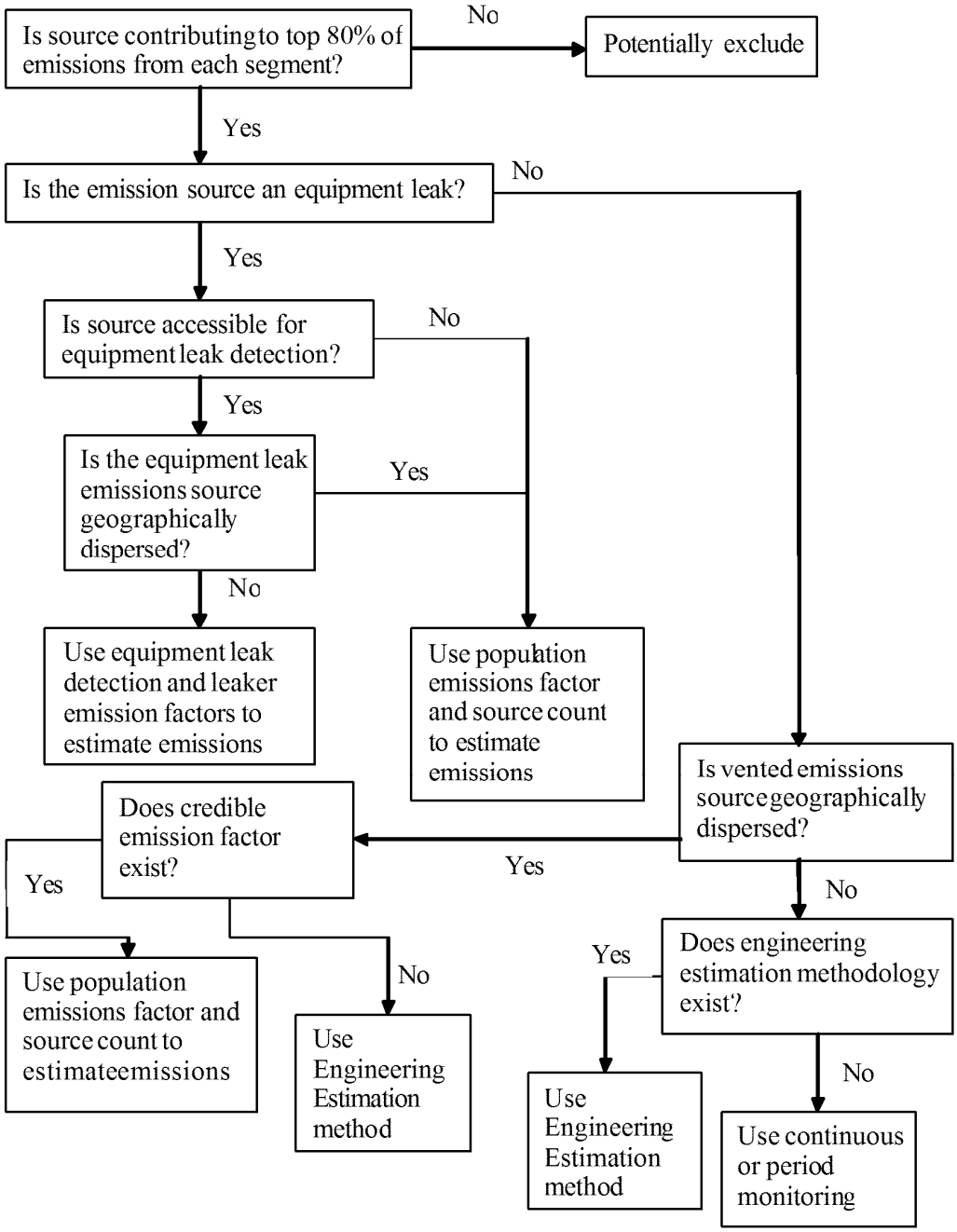
- *Applicability of Population or Leaker Emission factors* – When the total emissions from all leaking sources of the same type are divided by the total count of that source type then the resultant factor is referred to as population emissions factor. When the total emissions from all leaking sources of the same type are divided by the total count of leaking sources for that source type then the resultant factor is referred to as leaker emissions factor. For example, in an emissions detection and measurement study, if 10 out of 100 valves in the facility are found leaking then:

    - the total emissions from the 10 valves divided by 100 is referred to as population emissions factor
    - the total emissions from the 10 valves divided by 10 is referred to as leaker emissions factor

  Requiring emissions leak detection and application of a corresponding emissions factor results in lower reporting burden as compared to conducting actual measurements. Furthermore, the use of leaker emissions factors provides an estimate of "actual" emissions as opposed to the use of population emissions factor where the emissions from each facility can only be a "potential" of emissions.

Based on the criteria outlined above, a decision process was developed to identify the potential sources that could be included in the reporting rule. Figure 1: Decision Process for Emissions Source Selection shows the resulting decision tree that includes these criteria and supported the decision-making process. The decision process provided in Figure 1: Decision Process for Emissions Source Selection was applied to each emissions source in the natural gas segment of the U.S. GHG Inventory. The onshore petroleum production segment has emissions sources that either are equivalent to their counterparts in the natural gas onshore production segment or fall in the 20 percent exclusion category. Only CH_4 emissions from the petroleum segment were taken into consideration for this exercise given that, for most sources, non-combustion CO_2 emissions from the petroleum segment are negligible in comparison to CH_4 emissions from the same sources. The exception to these are flares and acid gas recovery units in EOR operations that have large CO2 emission, but EPA does not have any emissions estimates for these source (see Section 3 and (4)(c)(iv) of the TSD). Appendix A summarizes the results of this analysis and provides guidance on the feasibility of each of the monitoring options discussed previously.

Figure 1: Decision Process for Emissions Source Selection



iii. Address Sources with Large Uncertainties

As described in Section 3 of the TSD, the petroleum and natural gas industry inventories are primarily based on the EPA/GRI 1996 Study, however the emissions for several sources in the EPA/GRI study do not correctly reflect today's operational practices. In some cases, comprehensive and sufficient information is not publicly available to revise the national Inventory estimates. In cases where public data are available, it is often incomplete and does not represent the industry at a national level.

Over the years, new data and increased knowledge of industry operations and practices have highlighted the fact that emissions estimates for certain sources are understated in the US Inventory

- Condensate and petroleum storage tanks
- Natural gas well workovers
- Natural gas well completions
- Natural gas well liquid unloading
- Centrifugal compressor wet seals
- Flares
- Scrubber dump valve emissions through tanks
- Onshore combustion emissions

The decision tree was not necessarily ideal for the sources listed above because they are known to be underestimated in current inventories. Therefore, after careful evaluation, EPA determined that these are significant emission sources that should be included in a comprehensive petroleum and natural gas systems GHG reporting rule. The following emissions sources are believed to be significantly underestimated in the U.S. GHG Inventory: well venting for liquids unloading; gas well venting during well completions; gas well venting during well workovers; crude oil and condensate storage tanks; centrifugal compressor wet seal degassing venting; scrubber dump valves; onshore combustion; and flaring. Refer to Appendix B for a detailed discussion on how new estimates were developed for each of the underestimated sources; natural gas well workovers, natural gas well completions, and natural gas well blowdowns. For centrifugal wet seals, EPA used an emission factor from a presentation given at the 24th World Gas Conference.[5]

In addition, the U.S. GHG Inventory includes reasonable estimation of CH_4 and CO_2 combustion emissions from natural gas engines and turbines (except in onshore production), as well as petroleum refineries. Emissions from these sources were not considered further here because methods for calculating and reporting emissions from these sources are addressed in the background technical support documents for Stationary Combustion

[5] The Bylin, Carey (EPA) study reported wet seal degassing emission measurements from 48 centrifugal compressors. Five centrifugal compressors were found not emitting while, the remaining 43 emitted 14,860 thousand cubic meters per year. Twenty-three cubic feet per minute was determined by dividing the 14,860 by the 43 centrifugal compressors. Bylin, Carey (EPA), et. al (2009) *Methane's Role in Promoting Sustainable Development in Oil and Natural Gas Industry*. <presented at 24th World Gas Conference>

described in Subpart C and Petroleum Refineries described in Subpart Y of the of the final GHG reporting rule (40 CFR Part 98) respectively.

Onshore Combustion Emissions:
The EPA estimates onshore production combustions emissions in its national GHG inventory. However, there are two challenges with the way these data are collected that make it difficult to use this data to support potential future climate policies. First, combustion-related emissions are reported in the national inventory at a fairly high level of aggregation, making it difficult to discern facility-level emissions. Second, there are concerns that this aggregate estimate is underestimating the total emissions from this source. The National Inventory of U.S. GHG Emissions and Sinks uses the "lease and plant" fuel consumption data as reported by the Energy Information Administration (EIA) as activity data to apply an emissions factor to estimate emissions. However, EIA estimates the lease and plant volume using data available from individual petroleum and natural gas producing States. The States in turn require only the voluntary reporting of this data from petroleum and natural gas producing operators raising questions as to whether the national data are complete. In addition, this estimate may not include all of the combustion emissions resulting from contracted and/ or portable combustion equipment. Given the high level of aggregation of this data and the potential omissions of some fuel consumption in onshore production in the National Inventory, this source type would be valuable to include in the rule for a more complete picture of facility-related emissions from onshore production facilities.

iv. Identify Industry Segments to be Included

Based on the understanding of facility definitions for each segment of the petroleum and natural gas industry and the identification of potential sources for inclusion in a GHG reporting rule, the industry segments could be defined as follows:

> *Onshore Petroleum and Natural Gas Production Segment* – Onshore petroleum and natural gas production is an important segment for inclusion in a GHG reporting program, due to its relatively large share of emissions. However, in order to include this segment, it is important to clearly articulate how to define the facility and identify who is the reporter. Onshore production operations are a challenge for emissions reporting using the conventional facility definition of a "contiguous area" under a common owner/ operator. EPA evaluated possible options for defining a facility for onshore petroleum and natural gas production in order to ensure that the reporting delineation is clear, to avoid double counting, and ensure appropriate emissions coverage. One potential option considered was to define a facility for this segment as all petroleum or natural gas equipment on a well pad or associated with a well pad and CO_2 EOR operations that are under common ownership or common control and that are located in a single hydrocarbon basin as defined in 40 CRF Part 98.238. This includes leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility. In this case, the operator would be the

company or corporation holding the required permit for drilling or operating. If the petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the state or federal business income taxes may also be considered the owner or operator. Operational boundaries and basin demarcations are clearly defined and are widely known, and reporting at this level would provide the necessary coverage of GHG emissions to inform policy. This facility definition for onshore petroleum and natural gas production will result in 85% GHG emissions coverage of this industry segment.

EPA reviewed other possible alternatives to define a production facility such as at the field level. In such cases, the company (or corporation) operating in the field would report emissions. EPA analyzed this option and found that such a field level definition would result in a larger number of reporters and in lower emissions coverage than basin level reporting, since fields are typically a segment of a basin.

In addition to basin and field level reporting, one additional alternative is identifying a facility as an individual well pad, including all stationary and portable equipment operating in conjunction with that well, including drilling rigs with their ancillary equipment, gas/liquid separators, compressors, gas dehydrators, crude petroleum heater-treaters, gas powered pneumatic instruments and pumps, electrical generators, steam boilers and crude oil and gas liquids stock tanks. In reviewing this option, EPA found that defining a facility as a single wellhead would significantly increase the number of reporters to a program, lower emissions coverage, and potentially raise implementation issues. For a complete discussion of the threshold analysis and estimated emissions coverage for each of the onshore petroleum and natural gas production facility options considered, refer to Section 5 of the TSD.

É *Offshore Petroleum and Natural Gas Production Segment* – All of the production activities offshore take place on platforms. These platforms can be grouped into two main categories; wellhead platforms and processing platforms. Wellhead platforms consist of crude oil and/ or natural gas producing wellheads that are connected to processing platforms or send the hydrocarbons onshore. Processing platforms consist of wellheads as well as processing equipment such as separators and dehydrators, in addition to compressors. All platforms are within a confined area and can be distinctly identified as a facility. Since all sources are within a small area on and around the platform, all sources of emissions on or associated with offshore platforms could be monitored and reported.

É *Onshore Natural Gas Processing Segment* –Processing plants process the gas received from production and/ or gathering or boosting segments to remove hydrogen sulfide (H_2S) and/ or CO_2 from the natural gas, if any, separate the higher molecular weight hydrocarbons (ethane, propane, butane, pentanes, etc.) from the natural gas and compress the natural gas to be injected into the onshore natural gas transmission segment. Natural gas processing facilities have a well defined boundary within which all processes take place. All emissions sources in processing facilities could be monitored and included in a GHG reporting rule.

É *Onshore Natural Gas Transmission Compression* – Transmission compressor stations are the largest source of emissions on transmission pipelines and meet the conventional definition of a facility. Given the relatively large share of emissions from the compressor station, as compared to the pipeline segments between transmission compressor stations, the station may be the most logical place to capture emissions from this segment.

É *Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Segments* – All operations in an underground natural gas storage facility (except wellheads), LNG storage facility, and LNG import and export facilities are confined within defined boundaries. In the case of underground natural gas storage facilities, the wellheads are within short distances of the main compressor station such that it is feasible to monitor them along with the stations themselves. All three segments could be included in a GHG reporting rule.

É *Natural Gas Distribution Segment* – The distribution segment metering and regulator above ground stations and below ground vaults are identifiable as facilities. However, the magnitude of emissions from a single station or vault may not be significant, which would result in minimal coverage of emissions from this segment. Multiple stations or vaults collectively contribute to a significant share of emissions from the natural gas industry nationally, but they may not be considered one facility because they are not contiguous and there is no logical grouping unless the entire system is considered.

Another option for including distribution sector is adapting the facility definition from Subpart NN, Suppliers of Natural Gas and Natural Gas Liquids, of the MRR which defines a local distribution company (LDC) as a facility. In this case, the definition of natural gas distribution would be the distribution pipelines, metering and regulator stations and vaults that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system This facility definition provides clear reporting delineation because the equipment that they operate is clearly known, the ownership is clear to one company, and reporting at this level is consistent with the final MRR as well as other existing data reporting mechanisms. Additionally, this aggregation of equipment will include all the significant sources of emissions from the segment.

É *Petroleum Transportation Segment* – All the sources in the petroleum transportation segment were excluded as a result of the decision process. Hence, this segment may not be amenable to inclusion in a reporting program.

5. Options for Reporting Threshold

For each segment in the petroleum and natural gas industry identified above as amenable to a reporting program, four thresholds were considered for emissions reporting as applicable to

an individual facility; 1,000 metric tons of CO_2 equivalent ($MtCO_2e$) per year, 10,000 $MtCO_2e$, 25,000 $MtCO_2e$, and 100,000 $MtCO_2e$. A threshold analysis was then conducted on each segment to determine which level of threshold was most suitable for each industry segment. CH_4, CO_2, and N_2O emissions from each segment were included in the threshold analysis.

a. Threshold Analysis

For each segment, a threshold analysis was conducted to determine how many of the facilities in the segment exceed the various reporting thresholds, and the total emissions from these impacted facilities. This analysis was conducted considering equipment leak and vented CH_4 and CO_2 emissions, and incremental combustion CH_4, CO_2, and N_2O emissions. Incremental combustion emissions are those combustion emissions from facilities not already reported under Subpart C of the 40 CFR Part 98, but are required to be reported because the combined process emissions from Subpar W plus combustion emissions exceed the 25,000 metric tons CO_2e reporting threshold. The equipment leak and vented emissions estimates available from the U.S. GHG Inventory were used in the analysis. However, the emissions estimates for four sources, well venting for liquids unloading, gas well venting during well completions, gas well venting during well workovers, and centrifugal compressor wet seal degassing venting from the U.S. GHG Inventory were replaced with revised estimates developed as described in Appendix B. Centrifugal compressor emissions were revised using centrifugal compressor activity data from the U.S. Inventory and an emission factor from the 24th World Gas Conference[5]. Incremental combustion emissions were estimated using gas engine methane emissions factors available from the GRI study, back calculating the natural gas consumptions in engines, and finally applying a CO_2 emissions factor to the natural gas consumed as fuel. Nitrous Oxide emissions were also calculated similarly. In the case of offshore petroleum and natural gas production platforms combustion emissions are already available from the GOADS 2000 study analysis and hence were directly used for the threshold analysis. It must be noted that the threshold analysis for 40 CFR Part 98, Subpart W includes all equipment leak and vented emissions, but only incremental combustion emissions. Due to these reasons the total emissions from the threshold analysis does not necessarily match the U.S. GHG Inventory for all segments of the petroleum and natural gas industry. A detailed discussion on the threshold analysis is available in Appendix C.

The general rationale for selecting a reporting threshold could be to identify a level at which the incremental emissions reporting between thresholds is the highest for the lowest incremental increase in number of facilities reporting between the same thresholds. This would ensure maximum emissions reporting coverage with minimal burden on the industry. For example, for onshore production the emissions reporting coverage is 74 percent and the corresponding reporting facilities coverage is 2 percent for a threshold of 100,000 $MtCO_2e$ per year. The incremental emissions and facilities coverage is 11 and 2 percent (85 percent minus 74 percent and 4 percent minus 2 percent), respectively, for a 25,000 $MtCO_2e$ per year threshold. However, at the next reporting threshold level of 10,000 $MtCO_2e$ per year the incremental emissions and entities coverage is 6 and 5 percent, respectively. It can be seen that the incremental coverage of emissions decreases but the coverage of facilities increases.

Table 5 provides the details of the threshold analysis at all threshold levels for the different segments in the petroleum and gas industry. It must be noted that the threshold analysis estimates of emissions in this table are slightly different from the estimate of emissions in the April 2010 proposal. The slight decrease in reported emissions of 4 percent for the entire oil and gas sector resulted from data and calculation corrections in the transmission and LNG storage segments and use of different well property databases in onshore production (HPDI® in the final, as opposed to LASSER® in the April 2010 proposal). The same note applies to Table 7 below.

Table 5: Threshold Analysis for the Petroleum and Gas Industry Segments

Source Category	Threshold Level	Total National Emissions	Number of Facilities	Emissions Covered				Facilities Covered	
				Process Emissions ($MtCO_2e$/year)	Combustion CO_2 Emissions (Mt/year)	Total Emissions (tons $mtCO_2e$/yr)	Percent	Number	Percent
Onshore Natural Gas Production Facilities (Basin)	100,000	265,349,383	22,510	136,547,535	60,732,073	197,279,608	74%	385	2%
	25,000	265,349,383	22,510	152,395,746	73,695,453	226,091,199	85%	981	4%
	10,000	265,349,383	22,510	158,499,897	82,061,519	240,561,416	91%	1,929	9%
	1,000	265,349,383	22,510	165,212,244	96,180,842	261,393,085	99%	8,169	36%
Offshore Petroleum and Natural Gas Production Facilities	100,000	11,261,305	3,235	3,217,228	25,161	3,242,389	29%	4	0.12%
	25,000	11,261,305	3,235	4,619,175	500,229	5,119,405	45%	58	1.79%
	10,000	11,261,305	3,235	5,515,419	1,596,144	7,111,563	63%	184	5.69%
	1,000	11,261,305	3,235	6,907,812	3,646,076	10,553,889	94%	1,192	36.85%
Onshore Natural Gas Processing Facilities	100,000	33,984,015	566	24,846,992	27,792	24,874,783	73%	130	23%
	25,000	33,984,015	566	29,551,689	1,677,382	31,229,071	92%	289	51%
	10,000	33,984,015	566	30,725,532	2,257,443	32,982,975	97%	396	70%
	1,000	33,984,015	566	31,652,484	2,331,531	33,984,015	100%	566	100%
Onshore Natural Gas Transmission Facilities	100,000	47,935,158	1,944	24,197,401	7,834	24,205,235	50%	433	22%
	25,000	47,935,158	1,944	36,154,061	6,155,313	42,309,374	88%	1,145	59%
	10,000	47,935,158	1,944	37,593,627	9,118,603	46,712,230	97%	1,443	74%
	1,000	47,935,158	1,944	37,993,603	9,934,474	47,928,077	100%	1,695	87%
Underground Natural Gas Storage Facilities	100,000	9,730,625	397	3,557,040	0	3,557,040	37%	36	9%
	25,000	9,730,625	397	6,585,276	1,276,239	7,861,516	81%	133	34%
	10,000	9,730,625	397	7,299,582	1,685,936	8,985,518	92%	200	50%
	1,000	9,730,625	397	7,762,600	1,951,505	9,714,105	100%	347	87%
LNG Storage Facilities	100,000	2,113,601	157	596,154	25,956	622,110	29%	4	3%
	25,000	2,113,601	157	1,524,652	188,552	1,713,205	81%	33	21%
	10,000	2,113,601	157	1,626,435	204,297	1,830,731	87%	41	26%
	1,000	2,113,601	157	1,862,200	252,895	2,115,095	100%	54	34%
LNG Import Facilities[1]	100,000	315,888	5	314,803	0	314,803	100%	4	80%
	25,000	315,888	5	314,803	0	314,803	100%	4	80%
	10,000	315,888	5	314,803	0	314,803	100%	4	80%
	1,000	315,888	5	315,048	840	315,888	100%	5	100%
Natural Gas Distribution Facilities	100,000	25,258,347	1,427	18,470,457	0	18,470,457	73%	66	5%
	25,000	25,258,347	1,427	22,741,042	0	22,741,042	90%	143	10%
	10,000	25,258,347	1,427	23,733,488	0	23,733,488	94%	203	14%
	1,000	25,258,347	1,427	24,983,115	0	24,983,115	99%	594	42%

1. The only LNG export facility in Alaska has not been included in this analysis.

Note: Totals may not add exactly due to rounding. Equipment leak and vented emissions in the threshold analysis are a sum of facility level emissions for each segment. Hence the total equipment leak and vented emissions from each segment may not match the U.S. GHG Inventory.

As discussed above, alternative definitions of facility for onshore petroleum and natural gas production could be considered. One alternative option is applying the threshold at the field level. Table 7 provides the results of the threshold analysis for a field level facility definition. The results of this analysis show that at a 25,000 metric ton CO_2e threshold, 1,157 facilities would be covered and only 57 percent of national emissions. If the threshold were decreased to 1,000 metric tons CO_2e, over 80 percent of national emissions would be covered but the number of reporters would increase to over 22,000.

Table 7. Emissions coverage and number of reporting entities for field level facility definition

Threshold Level[2]	Emissions Covered		Facilities Covered	
	Metric tons CO_2e/year	Percent	Number	Percent
100,000	110,437,470	42%	306	0%
25,000	150,297,681	57%	1,157	2%
10,000	171,902,688	65%	2,549	4%
1,000	219,121,375	83%	22,459	33%

A third alternative for a facility definition was individual well pads as facilities for onshore petroleum and natural gas production segment. Four different scenarios were also considered below for applying thresholds at individual well pads.

- Case 1 (highest well pad emissions): Drilling and completion of an unconventional gas well early in the year with the well producing the remainder of the year with a full complement of common, higher process emissions equipment on the well pad including a compressor, glycol dehydrator, gas pneumatic controllers, and condensate tank without vapor recovery. We assumed that unconventional well completion does not employ "Reduced Emissions Completion" practices.

- Case 2 (second highest well pad emissions): Drilling and completion of a conventional gas well early in the year with the well producing the remainder of the year with a full complement of common, higher process emissions equipment on the well pad including a compressor, glycol dehydrator, gas pneumatic controllers, and condensate tank without vapor recovery.

- Case 3 (third highest well pad emissions): Drilling and completion of a conventional oil well early in the year with the well producing the remainder of the year with a full complement of common, higher process emissions equipment on the well pad including an associated gas compressor, glycol dehydrator, gas pneumatic

controllers, chemical injection pump, an oil heater-treater, and a crude oil stock tank without vapor recovery.

- Case 4 (fourth highest well pad emissions): Production at an associate gas and oil well (no drilling) with a compressor, dehydrator, gas pneumatics, oil heater/treater and oil stock tank without vapor recovery.

Table 8 below illustrates the average emissions for each scenario and the number of facilities that have emissions equal to or greater than that average. For example, in case 1, average emissions are 4,927 tons CO_2e/well pad. A threshold would have to be set as low as appropriately 5,000 tons CO_2e/well pad to capture even 6% of emissions from onshore petroleum and gas production. For the other cases, the threshold would have to be set lower than the thresholds considered for other sectors of the GHG reporting rule to capture even relatively small percentages of total emissions. In all cases, the number of reporters is higher than would be affected under the field or basin level options.

Table 8: Alternate Well-head Facility Definitions

	Case 1	Case 2	Case 3	Case 4
Average emissions (tons CO_2e / well pad)	4,927	700	700	370
Number of Reporters	3,349	38,949	66,762	166,690
Covered Emissions (metric tons CO2e)	16,498,228	40,943,092	50,572,248	87,516,080
Percent Coverage	6%	16%	19%	33%

The petroleum and natural gas industry may be somewhat unique when calculating facility emissions to be applied against a threshold for reporting. Subpart C in the GHG reporting rule excluded the calculation and reporting of emissions from portable equipment. This was one option considered for the petroleum and natural gas industry. However, given that portable equipment is so central to many of the operations in the petroleum and natural gas industry and such a large contributor to emissions for the industry, particularly for onshore petroleum and natural gas production, portable equipment emissions are an important source of emissions for inclusion a reporting rule. If these emissions were excluded from the threshold calculation, EPA estimates that a large number of facilities would fall below the threshold, preventing the collection of significant data from the industry that would be beneficial to the development of future climate policies and programs. Please see "Portable Combustion Emissions" memo under rulemaking docket EPA-HQ-OAR-2009-0923.

Another issue that concerns onshore petroleum and natural gas production is the number of equipment operating contractors that support the well operators. It is typical to find production well operators contracting out the majority of their process equipment from separation, dehydration, and tanks, up to gathering and boosting and transport. Hence requiring well operators to report only emissions from equipment they own or directly operate could lead to a significant reduction in emissions coverage. Accordingly, the final rule provides that emissions from such equipment must be reported whether from equipment contracted to, leased from, owned or run by a third party. For a more full discussion of this issue, see Vol. 9, Response to Legal Issues on Mandatory Greenhouse Gas Reporting Rule Subpart W – Petroleum and Natural Gas.

6. Monitoring Method Options

a. Review of Existing Relevant Reporting Programs/ Methodologies

To determine applicability of the different monitoring methods available, existing programs and guidance documents were reviewed. Table 4 shows a listing of the existing programs and guidance documents that were reviewed. All of the program and guidance documents provide direction on estimating CH_4 and/ or CO_2 emissions. All documents, in general, provide emissions rate (emissions factors) that can be used to estimate emissions and in some cases refer to continuous emissions monitoring.

b. Potential Monitoring Methods

Depending on the particular source to be monitored in a facility, several of the currently available monitoring methods for estimating emissions could be used.

i. Equipment Leak Detection

Traditional equipment leak detection technologies like the Toxic Vapor Analyzer (TVA) and the Organic Vapor Analyzer (OVA) are appropriate for use in small facilities with few pieces of equipment. However, comprehensive leak detection in large facilities can be cumbersome, time consuming, and in many cases costly. But new infrared remote equipment leak detection technologies are currently being used in the United States and internationally to efficiently

detect leaks across large facilities. Considering these factors, one of the following two technologies can be used to detect leaks in facilities depending on suitability;

Infrared Remote Equipment Leak Detectors
Hydrocarbons in natural gas emissions absorb infrared light. The infrared remote equipment leak detectors use this property to detect leakages in systems. There are two main types of detectors; a) those that scan the an area to produce images of equipment leaks from a source (passive instruments), and b) those that point or aim an IR beam towards a potential source to indicate presence of equipment leaks (active instruments).

An IR camera scans a given area and converts it into a moving image of the area while distinctly identifying the location where infrared light has been absorbed, i.e. the equipment leak source. The camera can actually "see" equipment leaks. The advantages of IR cameras are that they are easy to use, very efficient in that they can detect multiple leaks at the same time, and can be used to do a comprehensive survey of a facility. The main disadvantage of an IR camera is that it may involve substantial upfront capital investment depending on the features that are made available. Therefore, these cameras are most applicable in facilities with large number of equipment and multiple potential leak sources or when purchased at the corporate level, and then shared among the facilities, thereby lowering costs.

Aiming devices are based on infrared laser reflection, which is tuned to detect the interaction of CH_4 and other organic compounds with infrared light in a wavelength range where CH_4 has strong absorption bands, but do not visually display an image of the equipment leaks. Such devices do not have screens to view equipment leaks, but pin point the location of the emissions with a visual guide (such as a visible pointer laser) combined with an audible alarm when CH_4 is detected. These devices are considerably less expensive than the camera and also can detect equipment leaks from a distance (i.e. the instrument need not be in close proximity to the emissions). More time is required for screening, however, since each equipment (or component) has to be pointed at to determine if it is leaking. Also, if there are multiple leaks in the pathway of the IR beam then it may not accurately detect the right source of emissions.

Method For IR instruments that visually display an image of equipment leaks, the background of the emissions has to be appropriate for emissions to be detectable. Therefore, the operator should inspect the emissions source from multiple angles or locations until the entire source has been viewed without visual obstructions to identify all emissions. For other IR detection instruments, such as those based on IR laser reflection, instruments would have to monitor potential emissions sources along all joints and connection points where a potential path to the atmosphere exists. For example, a flange can potentially have leaks along its circumference and such surfaces will have to be monitored completely by tracing the instrument along each surface.

Calibration The minimum detectable quantity of equipment leaks using an IR instrument depends on a number of factors including manufacturer, viewing distance, wind speed, gas composition, ambient temperature, gas temperature, and type of background behind the equipment leaks. For best survey results, equipment leak detection can be performed under

favorable conditions, such as during daylight hours, in the absence of precipitation, in the absence of high wind, and, for active laser devices, in front of appropriate reflective backgrounds within the detection range of the instrument. The EPA Alternative Work Practice (AWP) requires optical imaging devices to detect a minimum flow rate, specified in Title 40 CFR Part 65 Section 7, before each use. The AWP specifies instructions for determining the minimum detectable flow rate, the purity of the calibration gas, and the allowed viewing distance. Equipment leak detection and measurement instrument manuals can also be used to determine optimal operating conditions to help ensure best results.

Toxic Vapor Analyzer (or Organic Vapor Analyzer)

TVAs and OVAs consist of a flame ionization detector that is used to detect the presence of hydrocarbons and measure the concentration of equipment leaks. It consists of a probe that is moved close to and around the potential emissions source and an emissions detection results in a positive reading on the instrument monitoring scale. The concentration can be used in conjunction with correlation equations to determine the leak rate. However, concentration is not a true measure of an emission's magnitude. Therefore concentration data from TVAs and OVAs, for the purposes of the rule, may be best suited for screening purposes only. The advantage of these instruments is that they have lower costs than IR cameras and several facilities conducting Leak Detection and Repair (LDAR) programs might already have these instruments, thereby reducing capital investment burden. But these instruments screen very slowly given that each potential emissions source has to be individually and thoroughly circumscribed less than 1 centimeter from the potentially leaking joints or seals.

Method TVAs and OVAs can be used for all equipment leak detection that is safely accessible at close-range. For each potential emissions source, all joints, connections, and other potential paths to the atmosphere would be monitored for emissions. Due to residence time of a sample in the probe, there is a lag between when an emission is captured and the operator is alerted. To pinpoint the source of the equipment leak, upon alert the instrument can be slowly retraced over the source until the exact location is found.

Calibration Method 21 guidance can be used to calibrate the TVA or OVA using guidelines from *Determination of Volatile Organic Compound Leaks* Sections 3, 6, and 7.

Acoustic Leak Detectors

Acoustic leak detectors are simple devices that filter out the low frequency vibrations and noise of heavy machinery operating and sense and measure the decibel reading of high frequency vibrations and noise of fluids leaking through small cracks or openings. Fluid flow through open valves has little difference in sonic generated noise between the inlet and outlet of a valve, or the valve body itself. Similarly tightly closed valves have little difference in sonic noise measured on the inlet, outlet or valve body. Valves which are not tightly closed (i.e. a crevice or deformation of the valve plug and seat) will generate a high frequency noise depending on the valve type and size, the pressure drop across the closed valve, and the fluid density. This frequency can be measured in decibels and correlated with through valve leakage rate.

Method

The instrument operator places the "stethoscope" like probe on the valve body or valve flange in one or more of the recommended locations, and observes the decibel reading displayed on the instrument digital signal indicator. This reading is documented in the field, along with the valve identification (valve number or location descriptor). The type of fluid, its density, and the system pressure upstream and downstream of the closed valve are also recorded to be entered along with the valve type (ball, plug, gate, pressure relief, etc) and nominal size) into an Excel spreadsheet supplied by the valve manufacturer. The through valve leakage rate is calculated by correlation algorithms developed by the instrument manufacturer.

Calibration

Calibration requirements are as provided by the manufacturer, depending on the type of acoustic detector.

ii. Emissions Measurement

A. Direct Measurement

Three types of technologies can be used where appropriate to measure or quantify the magnitude of emissions.

High Volume Sampler

A high volume sampler consists of a simple fixed rate induced flow sampling system to capture the emissions and measure its volume. The emissions and the air surrounding the emissions source are drawn into the instrument using a sampling hose. The instrument measures the flow rate of the captured volume of air and emissions mixture. A separate sample of the ambient air is taken by the instrument to correct for the volume of ambient air that is captured along with the emissions.

High volume samplers have moderate costs and have a potential capacity for measuring up to 30 leaking components per hour with high precision at 0.02 percent methane. This allows for reduced labor costs and survey times while maintaining precise results. For this reason, high volume samplers are considered the preferred and most cost-effective direct measurement option for emissions within their maximum range. However, large component emissions and many vent emissions are above the high volume sampler capacity and therefore warrant the use of other measurement instruments.

Method A high volume sampler is typically used to measure only emissions for which the instrument can intake the entire emissions from a single source. To ensure proper use of the instrument, a trained technician can conduct the measurements. The technician will have to be conversant with all operating procedures and measurement methodologies relevant to using a high volume sampler, such as positioning the instrument for complete capture of the emissions without creating backpressure on the source. If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions

from the source then anti-static wraps or other aids can be used to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual. The attachments help capture the emissions from different points on the source allowing the measurement of the emission by the high volume sampler.

Calibration The instrument can be calibrated at 2.5% and 100% CH_4 by using calibrated gas samples and by following the manufacturer's instructions for calibration.

Meters

Several types of meters measure natural gas flows and can be used for measurement of emissions from sources where the volume of emissions are large like in vent stacks.

Rotameter – A rotameter consists of a tapered calibrated transparent tube and a floating bob inside to measure emissions. To measure emissions a rotameter is placed over an emissions source (typically vents and open ended lines) and the emissions pass through the tube. As the emissions move through the tube it raises the floating bob to indicate the magnitude of emissions on the calibrated scale. Rotameters are most advantageous to use in cases where the emissions are very large. The disadvantage though is that it can only be used on leaks where the entire emissions can be captured and directed through the rotameter.

Turbine Meter –To measure emissions a turbine meter is placed over an emissions source and the emissions pass through the tube. As the emissions move through the tube it spins the turbine; the rate at which the turbine spins indicates the magnitude of emissions. Like rotameters, turbine meters are most advantageous to use in cases where emissions are very large. The disadvantage is that it can only be used on emissions that can be entirely captured and directed through the meter.

Hotwire Anemometer – Hotwire anemometers measure emissions velocity by noting the heat conducted away by the emissions. The core of the anemometer is an exposed hot wire either heated up by a constant current or maintained at a constant temperature. In either case, the heat lost to emissions by convection is a function of the emissions velocity. Hotwire anemometers are best for measuring vents and open ended lines of known cross-sectional area and do not require complete capture of emissions. Hot wire anemometers have low levels of accuracy since they measure velocity that is converted into mass emissions rate.

Pitot Tube Flow Meter – A simple pitot tube is a right angled tube open at one end and closed at the other. The closed end is connected to a transducer to measure pressure of the inflowing emissions. The open end is aligned parallel to the direction of emissions flow. Emissions are directed into the tube so that the pressure required to bring the air inside the tube to stagnation is measured. The difference in pressure between the interior of the pitot tube and the surrounding air is measured and converted to an emissions rate. Pitot tube flow meters can be used when the cross-sectional area of an emitting vent or open ended line is known, or when the entire emission can be directed into the tube. The pitot tube flow meter measures pressure

differential that is converted to mass emissions rate. The pitot tube detects the flow velocity at only one point along the flowstream, hence the placement of the pitot tube inside the pipe where the flow is to be measured is critical to determine a representative flow volume, and not a location-specific flow volume, which can give erroneous results. It has relatively low accuracy compared to most flow meters, due to the low pressure drop measured. This also makes it vulnerable to fluctuations from turbulence changes in the flow stream. Although inaccurate compared to most meters, the pitot tube is one of the least expensive flow meters available.

Vane Anemometer – A vane anemometer channels the emissions over a rotating vane that in turn rotates a fan to measure the velocity of emissions. The number of revolutions of the fan are detected and measured and converted to a flow velocity. Using the cross section of flow of the emissions, the volumetric flow rate of emissions can be estimated. A vane anemometer is best used for lines that have known cross-sectional areas. The disadvantage is if the flow direction of the emissions changes with respect to the axis of rotation of the vanes, it can result in errors in velocity and flow rate estimation.

Method To ensure accurate measurements when using metering (e.g. rotameters, turbine meters, and others), all emissions from a single source will have to be channeled directly through the meter. An appropriately sized meter can be used to prevent the flow from exceeding the full range of the meter and conversely to have sufficient momentum for the meter to register continuously in the course of measurement.

Calibration The meters can be calibrated using either one of the two methods provided below:

(A) Develop calibration curves by following the manufacturer's instruction.

(B) Weigh the amount of gas that flows through the meter into or out of a container during the calibration procedure using a master weigh scale (approved by the National Institute of Standards and Technology (NIST) or calibrated using standards traceable by NIST) that has a very high degree of accuracy. Determine correction factors for the flow meter according to the manufacturer's instructions, record deviations from the correct reading at several flow rates, plot the data points, compare the flow meter output to the actual flow rate as determined by the master weigh scale and use the difference as a correction factor.

(C) The Final GHG Reporting Program provides guidance on calibration for meters in section §98.3(i).

Calibrated Bagging

A calibrated bag (also known as a vent bag) made of anti-static material is used to enclose an emissions source to completely capture all the leaking gas. The time required to fill the bag with emissions is measured using a stop watch. The volume of the bag and time required to

fill it is used to determine the mass rate of emissions. Calibrated bags have a very high accuracy, since all the emissions are captured in the measurement.

Calibrated bags are the lowest cost measurement technique, and can measure up to 30 leaking components in an hour, but may require two operators (one to deploy the bag, the other to measure time inflation). It is a suitable technique for emission sources that are within a safe temperature range and can be safely accessed. The speed of measurement is highly dependent on the emissions rate and the results are susceptible to human error in enclosing the emission source and taking the measurement data, leading to lower precision and accuracy. For those sources outside the capacity of high volume samplers and within the limitations of bagging, this would be a second best choice for quantification.

Method Calibrated bags can be used only where the emissions are at near-atmospheric pressures and the entire emissions volume can be captured for measurement. Using these bags on high pressure vent stacks can be dangerous. For conducting measurement the bag is physically held in place by a trained technician, enclosing the emissions source, to capture the entire emissions and record the time required to completely fill the bag. Three measurements of the time required to fill the bag can be conducted to estimate the emissions rates. The average of the three rates will provide a more accurate measurement than a single measurement.

Calibration To ensure accurate results, a technician can be trained to obtain consistent results when measuring the time it takes to fill the bag with emissions.

All of the emissions measurement instruments discussed above measure the flow rate of the natural gas emissions. In order to convert the natural gas emissions into CO_2 and CH_4 emissions, speciation factors determined from natural gas composition analysis must be applied. Another key issue is that all measurement technologies discussed require physical access to the emissions source in order to quantify emissions.

B. Engineering Estimation and Emission Factors

For several emissions sources, there are viable alternatives to physical measurement for calculating emissions. For example, emissions to the atmosphere due to emergency conditions from vessels or other equipment and engineered emissions from equipment like pneumatic devices can be estimated or quantified using engineering calculations. This is referred to as engineering estimation. Emission factors can be considered for nearly every source where emissions data is available, however, they usually have high uncertainties. Emissions factors may be appropriate for frequent, geographically sparse emission sources such as pneumatic devices. Several sources are outlined below along with relevant engineering estimation methods that can be used to estimate GHG gas emissions from each source.

1. Natural Gas Driven Pneumatic Pumps

Leaks from natural gas driven pneumatic pumps can be calculated using data obtained from the manufacturer for natural gas emissions per unit volume of liquid pumped at operating pressures. This information is available from the pump manufacturer in their manuals. Operators can maintain a log of the amount of liquids pumped annually for individual pneumatic pumps and use Equation 1 below for calculating emissions:

$$E_{s,n} = F_s * V \qquad \textbf{Equation 1}$$

where,

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet per year

F_s = Natural gas driven pneumatic pump gas emission in "emission per volume of liquid pumped at operating pressure" in scf/gallon at standard conditions, as provided by the manufacturer

V = Volume of liquid pumped annually in gallons/year

If manufacturer data for a specific pump is not available, then data for a similar pump model of the same size and operational characteristics can be used to estimate emissions. As an alternative to manufacturer data on pneumatic pump natural gas emissions, the operator can conduct a one-time measurement to determine natural gas emissions per unit volume of liquid pumped using a calibrated bag for each pneumatic pump, when it is pumping liquids.

Due to the geographically isolated nature of pneumatic pumps, if manufacturer data is not readily available or would result in high burden to obtain the data, pneumatic pump emissions can also be quantified using published emission factors. The use of emission factors is less burdensome than collecting manufacturer data from each pneumatic pump but can be inaccurate due to limited data and variable pump design. However, the resulting information can still be useful for the purposes of informing policy because it will provide updated activity data on the number and type of pneumatic pumps in operation. See Appendix G for a discussion of population emission factors for pneumatic pumps and see Section (6)(d) of the TSD for how to calculate emissions from population factors. Emissions from natural gas driven pneumatic pumps can be calculated using an emissions factor as follows;

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24 * 365 \qquad \textbf{Equation 2}$$

where,

$Mass_{s,i}$ = Annual total mass GHG emissions in metric tons per year at standard conditions from all natural gas driven pneumatic pumps at the facility, for GHG_i

$Count$ = Total number of natural gas driven pneumatic pumps at the facility

EF	=	Population emission factors for natural gas driven pneumatic pumps listed in Appendix G for onshore petroleum and natural gas production, onshore natural gas transmission, and underground natural gas storage facilities, respectively
GHG_i	=	for onshore petroleum and natural gas production facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas; for other facilities GHG_i equals 1
$Conv_i$	=	conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2
24 * 365	=	conversion to yearly emissions estimate

2. Natural Gas Driven Pneumatic Manual Valve Actuators

Emissions from natural gas driven pneumatic manual valve actuators can be calculated using data obtained from the manufacturer for natural gas emissions per actuation. Operators can maintain a log of the number of manual actuations annually for individual pneumatic devices and use Equation 3 below:

$$E_{s,n} = A_s * N \qquad \textbf{Equation 3}$$

where,

$E_{s,n}$	=	natural gas emissions at standard conditions
A_s	=	natural gas driven pneumatic valve actuator natural gas emissions in "emissions per actuation" units at standard conditions, as provided by the manufacturer.
N	=	Number of times the pneumatic device was actuated through the reporting period

As an alternative to manufacturer data, the operator could conduct a one-time measurement to determine natural gas emissions per actuation using a calibrated bag for each pneumatic device.

3. Natural Gas Driven Pneumatic Bleed Devices

Pneumatic devices typically fall in three categories; low bleed devices, high bleed devices, and intermittent bleed devices. Low bleed devices are devices that bleed less than 6 scf of natural gas per hour. High bleed devices are devices that bleed more than 6 scf of natural gas per hour.[6,7] Intermittent bleed devices are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but do not bleed continuously. Given the vast difference in bleed rates, low bleed devices contribute to a

[6] "Opportunities to Reduce Anthropogenic Methane Emissions in the United States," EPA 430-R-93-012, October 1993
[7] PG&E (Pacific Gas and Electric). 1990. Unaccounted for Gas Project Summary Volume, PG&E Research and Development; San Ramon, CA: GRI-90/0067.1

small portion of the total emissions from pneumatic devices nationally. Therefore, it may be feasible to provide an emissions factor approach for low bleed pneumatic devices to reduce burden. The following are two different options for determining emissions from low bleed, high bleed, and intermittent pneumatic devices.

Emissions from a natural gas pneumatic high bleed device venting can be calculated using a specific pneumatic device model natural gas bleed rate during normal operation as available from the manufacturer. If manufacturer data for a specific device is not available then data for a similar size and operation device can potentially be used to estimate emissions. The natural gas emissions for each bleed device can be calculated as follows;

$$E_{s,n} = B_s * T \qquad \textbf{Equation 4}$$

where,

$E_{s,n}$ = Annual natural gas emissions at standard conditions, in cubic feet

B_s = Natural gas driven pneumatic device bleed rate volume at standard conditions in cubic feet per minute, as provided by the manufacturer

T = Amount of time in minutes that the pneumatic device has been operational through the reporting period

Due to the geographically isolated nature of pneumatic devices, if manufacturer data is not readily available or would result in high burden to obtain the data, pneumatic device emissions can also be quantified using published emission factors. The use of emission factors is less burdensome than collecting manufacturer data from each device, but can be inaccurate due to limited data and variable design. However, the resulting information can still be useful for the purposes of informing policy because it will provide updated activity data on the number and type of pneumatic pumps in operation. See Appendix G for a discussion of population emission factors for pneumatic devices and see Section (6)(d) of the TSD for how to calculate emissions from population factors. Emissions from natural gas pneumatic low bleed device venting can be calculated using emissions factor as follows;

$$Mass_{s,i} = Count * EF * GHG_i * Conv_i * 24*365 \qquad \textbf{Equation 5}$$

where,

$Mass_{s,i}$ = Annual total mass GHG emissions in metric tons per year at standard conditions from all natural gas pneumatic low bleed device venting at the facility, for GHG i

$Count$ = Total number of natural gas pneumatic low bleed devices at the facility

EF = Population emission factors for natural gas pneumatic low bleed device venting listed in Appendix G for onshore petroleum and natural gas

production, onshore natural gas transmission, and underground natural gas storage facilities, respectively

GHG_i = for onshore petroleum and natural gas production facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas; for other facilities GHG_i equals 1

$Conv_i$ = conversion from standard cubic feet to metric tons CO_2e; 0.000410 for CH_4, and 0.00005357 for CO_2

24 * 365 = conversion to yearly emissions estimate

4. Acid Gas Removal (AGR) Vent Stacks

AGR vents consist of both CO_2 and CH_4 emissions. CO_2 emissions from AGR units can be reliably estimated using continuous emissions monitoring (CEMS) systems, mass balance approach, or one of the standard simulation software packages. CH_4 emissions can only be estimated using simulation software packages. It must be noted, however, that CH_4 emissions from AGR vents are insignificant, 0.06 percent of the total volume of CO_2 and CH_4 emissions. The mass balance approach has the advantage of being usable in systems that use membrane, molecular sieves, or absorbents other than amines; simulation software packages currently do not provide an option for these types of technologies.

Some facilities may have CEMS installed on their AGR unit vent stacks. In such a case, if the CEMS can reliably measure CO_2 volumes then the measurements from CEMS can sufficiently inform on the CO_2 emissions from AGR units. Alternatively, if the vent stack has a meter on it then the CO_2 emissions can be estimated using this metered vent stack gas volume and the percent CO_2 in the vent stack gas.

Operators can calculate emissions from acid gas removal vent stacks using simulation software packages, such as ASPEN™ or AMINECalc™. Different software packages might use different calculations and input parameters to determine emissions from an acid gas removal unit. However, there are some parameters that directly impact the accuracy of emissions calculation. Therefore, any standard simulation software could be used assuming it accounts for the following operational parameters:

- Natural gas feed temperature, pressure, and flow rate;
- Acid gas content of feed natural gas;
- Acid gas content of outlet natural gas;
- Unit operating hours, excluding downtime for maintenance or standby;
- Emissions control method(s), if any, and associated reduction of emissions;
- Exit temperature of natural gas; and
- Solvent pressure, temperature, circulation rate, and weight.

CO_2 emissions from AGR unit vent stacks can also be calculated using mass balance approach from the throughput of the AGR unit and gas composition as follows;

$$E_{a,CO2} = \left(V + \alpha * \left(V * \left(Vol_I - Vol_O\right)\right)\right) * \left(Vol_I - Vol_O\right)$$ **Equation 6**

where,

$E_{a,CO2}$ = Annual volumetric CO2 emissions at actual condition, in cubic feet per year.

V = Total annual volume of natural gas flow into or out of the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section of the TSD.

α = Factor is 1 if the outlet stream flow is measured. Factor is 0 if the inlet stream flow is measured.

Vol_I = Volume fraction of CO2 content in natural gas into the AGR unit as determined in paragraph (d)(7) of this section.

Vol_O = Volume fraction of CO2 content in natural gas out of the AGR unit as determined in paragraph (d)(8) of this section of the TSD.

Sometimes AGR units have a continuous gas analyzer in which case they can be used to determine Vol_I and Vol_O.

There are gas processing plants that capture CO_2 for EOR or carbon sequestration projects. In such cases, the emissions E_{CO2} can be adjusted downward to account for the percentage of total emissions captured.

5. Blowdown Vent Stacks

Emissions from blowdown vent stacks can be calculated using the total physical volume between isolation valves (including all natural gas-containing pipelines and vessels) and logs of the number of blowdowns for each piece of equipment using Equation 7 below:

$$E_{s,n} = \left[V_v \left[\frac{(459.67 + T_s)P_a}{(459.67 + T_a)P_s} \right] - V_v * C \right]$$ **Equation 7**

where,

Es,n = *Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.*

N = *Number of repetitive blowdowns for each equipment type of a unique volume in calendar year.*

Vv = *Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) between isolation valves in cubic feet.*

C = *Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.*

Ts = *Temperature at standard conditions (^oF).*

Ta = *Temperature at actual conditions in the blowdown equipment chamber (^oF).*

Ps = *Absolute pressure at standard conditions (psia).*

Pa = *Absolute pressure at actual conditions in the blowdown equipment chamber (psia).*

6. Dehydrator Vent

There are two predominant types of technologies that are used to dehydrate natural gas. The first type is the most prevalent and uses liquid tri-ethylene glycol for dehydration, typically referred to as glycol dehydrators. The second type of dehydrators use solid desiccants to extract water from natural gas. For glycol dehydrators, when contacted with natural gas for dehydration, the glycol absorbs some amount of natural gas, which is released as emissions during its regeneration. Standard simulation software packages that use some form of equilibrium analysis can estimate emissions from such liquid glycol type dehydrators. On the other hand, in desiccant dehydrators the solid desiccant itself does not absorb any significant quantities of natural gas. But emissions result when the desiccant dehydrator is opened to the atmosphere for the regeneration of the desiccant, which results in the release of natural gas trapped in the desiccant dehydrator vessel. Hence, for desiccant dehydrators standard simulation software packages cannot be used. However, calculative methods can be used to determine emissions from solid desiccant type dehydrators. The two monitoring methods for the two different types for dehydrators are as below.

Emissions from a dehydrator vents can be calculated using a simulation software package, such as GLYCalc™. There may be several other simulation packages, such as Aspen HYSYS, that can also estimate emissions from glycol dehydrators. However, GLYCalc™ is the most widely used software and referenced by several State and Federal agencies in their programs and regulations. Different software packages might use different calculations and input parameters to determine emissions from dehydration systems. However, there are some parameters that directly impact the accuracy of emissions calculation. Therefore, any standard simulation software could be used provided it accounts for the following operational parameters:

- Feed natural gas flow rate;
- Feed natural gas water content;
- Outlet natural gas water content;
- Absorbent circulation pump type(natural gas pneumatic/ air pneumatic/ electric);
- Absorbent circulation rate;
- Absorbent type: including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG);
- Use of stripping natural gas;
- Use of flash tank separator (and disposition of recovered gas);
- Hours operated; and
- Wet natural gas temperature, pressure, and composition.

For dehydrators that use desiccant emissions can be calculated from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using Equation 8 below:

$$E_{s,n} = \frac{(H * D^2 * P * P_2 * \%G * 365 days / yr)}{(4 * P_1 * T * 1{,}000 cf / Mcf * 100)} \qquad \textbf{Equation 8}$$

where,

$E_{s,n}$	=	Annual natural gas emissions at standard conditions
H	=	Height of the dehydrator vessel (ft)
D_v	=	Inside diameter of the vessel (ft)
P_1	=	Atmospheric pressure (psia)
P_2	=	Pressure of the gas (psia)
P	=	pi (3.14)
$G_{\%}$	=	Percent of packed vessel volume that is gas
T	=	Time between refilling (days)
100	=	*Conversion of %G to fraction.*

Some dehydrator vented emissions are sent to a flare. Annual emissions from dehydrator vents sent to flares can be calculated using the methodology under Section 8 of the TSD for flares. Alternatively, a simple combustion efficiency factors, such as 98 percent, can be used in conjunction with a CO_2 emissions factor for natural gas to estimate emissions from glycol dehydrator vents to flare stack.

7. EOR injection pump blowdown.

EOR operations use pumps to inject supercritical phase CO_2 into reservoirs. For maintenance, these pumps may be blown down to release all the supercritical phase CO_2. The volume of CO_2 released to during such blow down practices can be calculated using the total volume between isolation valves (including, but not limited to, pipelines, compressors and vessels).The emissions can be calculated using Equation 9 below.

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3} \qquad \textbf{Equation 9}$$

where,

$Mass_{c,i}$	=	Annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns.

N	=	Number of blowdowns for the equipment in calendar year.
V_v	=	Total volume in cubic meters of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels between isolation valves.
R_c	=	Density of critical phase EOR injection gas in kg/m^3. Use an appropriate standard method published by a consensus-based standards organization to determine density of super critical EOR injection gas.
GHG_i	=	mass fraction of GHG*i* in critical phase injection gas

C. Emission Factors

The EPA/ GRI and EPA/Radian studies provide emissions factors for almost all the emissions sources in the petroleum and natural gas industry. These can potentially be used to estimate emissions for reporting under the rule. However, the emissions factors are not appropriate for all the emissions sources. The emissions factors were developed more than a decade ago when the industry practices were much different from now. In some cases, the emissions factors were developed using limited sample data and knowledge about the industry's operations (e.g., wells, compressors). While the available emission factors alone may not be appropriate for GHG reporting, certain emission factors may be sufficient, under certain circumstances, to calculate and characterize GHG emissions. Also, the introduction of many emissions reduction technologies are not reflected in the emissions factor estimates. However, the two studies provide raw emission data that in conjunction with newer publically available data (e.g., Clearstone 2006 study) could be used for developing emission factors for certain sources. Refer to Section 4(c)(ii), 6(c), and Appendix F and G of the TSD for a complete discussion of the use of emission factors in the reporting rule.

D. Combination of Direct Measurement and Engineering Estimation

Emissions from several sources can be estimated using a combination of direct measurement and engineering estimation. Direct measurement can provide either a snapshot of the emissions in time or information on parameters that can be used for using a calculative method to estimate emissions. Following are options for using such a combination of monitoring methods to estimate emissions.

8. Flare stacks

Flares typically burn two types of hydrocarbon streams; continuous and intermittent. Continuous streams result from vented emissions from equipment such as glycol dehydrators and storage tanks. Intermittent streams result from such sources as emergency releases from equipment blowdown. It must be noted that most of these streams, continuous or intermittent, can be covered using monitoring methods already provided on an individual emissions source level.

Flare emissions whether from continuous or intermittent streams can be monitored using one of the following monitoring methods

Method 1:

Many facilities, such as in the processing sector, may already have a continuous flow monitor on the flare. In such cases, the measured flow rates can be used when the monitor is operational, to calculate the total flare volumes for the calendar year.

Method 2:

Another option is to require the estimation of all streams of hydrocarbons going to the flare at an individual emissions source level. Here engineering calculation and other methods described for different sources in this Section of the TSD can be used to estimates of volume flare gas

Method 3:

When the flare stream is mostly continuous, a flow velocity measuring device (such as hot wire anemometer, pitot tube, or vane anemometer) can be inserted directly upstream of the flare stack to determine the velocity of gas sent to flare. The GHG volumetric emissions at actual conditions can then be calculated as follows.

$$E_{a,CH4}(un-combusted) = V_a * (1-\eta) * X_{CH4}$$ **Equation 10**

$$E_{a,CO2}(un-combusted) = V_a * X_{CO2}$$ **Equation 11**

$$E_{a,CO2}(combusted) = \sum_j \eta * V_a * Y_j * R_j$$ **Equation 12**

$$E_{a,i} = E_{a,CO2}(combusted) + E_{a,i}(un-combusted)$$ **Equation 13**

where,

$E_{a,i}(un\text{-}combusted)$	=	Contribution of annual un-combusted emissions from flare stack in cubic feet, under ambient conditions, for both CH_4 and CO_2 as described in Equation 10 and Equation 11.
$E_{a,CO2}(combusted)$	=	Contribution of annual emissions of CO_2 from combustion from flare stack, in cubic feet, under ambient conditions
$E_{a,i}(total)$	=	Total annual emissions from flare stack in cubic feet, under ambient conditions
V_a	=	Volume of natural gas sent to flare in cubic feet, during the year

η	=	Percent of natural gas combusted by flare (default is 98 percent)
X_i	=	Concentration of GHG_i in gas to the flare; where i = CO_2 or CH_4.
Y_j	=	Concentration of natural gas hydrocarbon constituents *j* (such as methane, ethane, propane, butane, and pentanes plus).
R_j	=	Number of carbon atoms in the natural gas hydrocarbon constituent *j*; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus)

In some cases the facility may have a continuous gas composition analyzer on the flare. Here the compositions from the analyzer can be used in calculating emissions. If an analyzer is not present then a sample of the gas to the flare stack can be taken every quarter to evaluate the composition of GHGs present in the stream. The natural gas composition analyses can be conducted using ASTM D1945-03. It must be noted that for processing plants there are two distinct streams of natural gas with significant differences in composition. The natural gas stream upstream of the de-methanizer can be expected to have higher C2+ components as opposed to the residue stream downstream of the de-methanizer. In addition, the CO_2 content in natural gas can change significantly after acid gas removal. Finally, processing plants may send pure streams of separated hydrocarbons such as ethane, propane, butane, iso-butane, or pentanes plus to the flare during an emergency shutdown of any particular equipment. Such variations in hydrocarbon streams being sent to the flare would have to be accounted for in the monitoring methodology.

9. Compressor wet seal degassing vents

In several compressors, the wet seal degassing vents emit flash gas from degassed oil straight into or close to the compressor engine exhaust vent stack. The temperatures at the degassing vent exit are very high due to the proximity to the engine exhaust vent stack. In such cases, emissions can be estimated using a flow velocity measuring device (such as hot wire anemometer, pitot tube) or a flow rate measurement device such as vane anemometer, which can be inserted directly upstream of the degassing unit vent exit to determine the velocity or flow rate of gas sent to the vent. If a velocity measuring device is used then the volume of natural gas sent to vent can be calculated from the velocity measurement using the manufacturer manual for conversion. Annual emissions can be estimated using meter flow measurement as follows:

$$E_{a,i} = MT * T * M_i * (1 - B) \qquad \textbf{Equation 14}$$

where,

$E_{a,i}$ = Annual GHG_i (either CH_4 or CO_2) volumetric emissions at ambient conditions

MT = Meter reading of gas emissions per unit time

T = Total time the compressor associated with the wet seal(s) is operational in the calendar year

M_i = Mole percent of GHG_i in the degassing vent gas

B = percentage of centrifugal compressor wet seal degassing vent gas sent to vapor recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapor recovery system or recycle to fuel gas system

A sample representative of the gas to the degassing vent can be taken every quarter to evaluate the composition of GHGs present in the stream using ASTM D1945-03. Some facilities may send their degassing vent vapors to a flare or to fuel use. The monitoring method will have to account for this.

10. Reciprocating compressor rod packing venting

There are three primary considerations for emissions from rod packing on reciprocating compressors. First, the rod packing case may or may not be connected to an open ended line or vent. Second, the rod packing may leak through the nose gasket in addition to the emissions directed to the vent. And third, the emissions from rod packing will vary depending on the mode of operation of the reciprocating compressor – running, standby and pressurized, or standby and de-pressurized.

If the rod packing case is connected to an open ended line or vent then emissions from the rod packing case can be estimated using bagging or high volume sampler. Alternatively, a temporary meter such as vane anemometer or permanent meter such as orifice meter can be used to measure emissions from rod packing vents.

If the rod packing case is open to the atmosphere then the emissions from the rod packing case will be mingled with the emissions from the nose gasket. The emissions from an open rod packing case usually will migrate to the distance piece (dog house), and if the distance piece is enclosed then this emissions will migrate to the engine crank case, before being emitted to the atmosphere. There are two possible options to monitor these emissions. The first option is to use an emissions factor for rod packing along with a population count. The second option is to require equipment leak detection and measurement to determine the exact location and volume of emission.

Typically, rod packing emissions vary with the mode of operation of the compressor. The emissions are highest when the compressor is operating and lower when they are in standby pressurized mode. When the compressor is standby de-pressurized there might be some migration of natural gas from the unit isolation valve through the rod packing. But rod packing emissions from leaking unit isolation valves is for the most part negligible because unit isolation valves leak primarily through the blowdown vent stack. Hence to correctly

characterize annual emissions from rod packing, estimation of emissions at two compressor modes, operating and standby pressurized, may be required.

11. Compressor isolation valve and blowdown valve

Blowdown valves on a compressor are used to depressurize and release all of the natural gas in the compressor chambers when the compressor is taken offline. These blowdown valves, however, can leak in some cases when the compressor is in operating or standby pressurized modes. Isolation valves are used to isolate the compressor chambers from the pipeline that connects the natural gas flow into and out of the compressor. These isolation valves can leak when the compressor is take offline. Both the blowndown valve and isolation valve are typically connected to the blowdown vent system. The emissions from leaks in an isolation valve or blowdown valve can be detected and measured using detection and measurement methods as discussed in Sections (6)(b)(i) and (6)(b)(ii)(A) of the TSD.

12. Storage tanks

Emissions from storage tanks can be estimated using one of the following four methods.

Method 1:

In the case of storage tanks, emissions rates are not constant; and thus, a one-time measurement may not provide accurate emissions rates for the entire reporting period. To accurately estimate emissions from storage tanks, it is necessary to conduct multiple measurements during a cycle of operation that is representative of the tank operations through the year. Equation 15 below can be used to calculate GHG emissions:

$$E_{a,h} = Q \times ER \qquad \textbf{Equation 15}$$

where,

$E_{a,h}$ = hydrocarbon vapor emissions at ambient conditions, in cubic meters

Q = storage tank total annual throughput, in barrels

ER = measured hydrocarbon vapor emissions rate per throughput (e.g. meter/barrel)

ER can be estimating using the following procedure:

- The hydrocarbon vapor emissions from storage tanks can be measured using a flow meter for a test period that is representative of the normal operating conditions of the storage tank throughout the year and which includes a complete cycle of accumulation of hydrocarbon liquids and pumping out of hydrocarbon liquids from the storage tank.
- The throughput of the storage tank during the test period can be recorded.

- The temperature and pressure of hydrocarbon vapors emitted during the test period can be recorded.
- A sample of hydrocarbon vapors can be collected for composition analysis.

Method 2:

A second method is to use simulation software such as E&P Tank (GEO-RVP) to estimate vented emissions from storage tanks. Therefore, any standard simulation software could be used assuming it accounts for the following operational parameters:

- Feed liquid flow rate to tank;
- Feed liquid API gravity;
- Feed liquid composition or characteristics;
- Upstream (typically a separator) pressure;
- Upstream (typically a separator) temperature;
- Tank or ambient pressure; and
- Tank or ambient temperature;
- Sales oil API gravity;
- Sales oil production rate;
- Sales oil Reid vapor pressure;

Method 3:

A third method to estimating emissions from storage tanks is to use the Peng-Robinson equation directly instead of using a simulation software. The Peng-Robinson equation is the basis behind most of the simulation softwares and therefore will result in estimates similar to *Method 2* above.

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2}$$ **Equation 16**

where:

p = Absolute pressure
R = Universal gas constant
T = Absolute temperature
V_m = Molar volume $= \frac{0.45724R^2T_c^2}{p_c} = \frac{0.7780RT_c}{p_c}$

$$\alpha = \left[1 + \left(0.37464 + 1.54226\omega - 0.26992\omega^2\right)\left(1 - \sqrt{\frac{T}{T_c}}\right)\right]^2$$

where:

Ω = Acentric factor of the species
Tc = Critical temperature

Pc = Critical pressure

Method 4:

A conservative method to estimate GHG emissions from flashing in storage tanks is to take a sample of liquids at the low pressure separator (i.e. the last separator before the liquids enter the storage tank) and then assume that all the CH_4 and CO_2 dissolved in this sample is released to the atmosphere.

Method 5:

A fifth method for storage tank vented emissions quantification is use of the Vasquez-Beggs equation. This correlation equation provides an estimate of the gas-to-oil ratio for flashing tank vapors; however, it does not provide the GHG of the vapors, so composition analysis of tank vapors is still required. Equation 17 demonstrates the use of this correlation equation:

$$GOR = A \times G_{fg} \times \left(P_{sep} + 14.7\right) \times \exp\left[\frac{C \times G_{oil}}{T_{sep} + 460}\right] \qquad \textbf{Equation 17}$$

where,

GOR	=	ratio of flash gas production to standard stock tank barrels of oil produced, in standard cubic feet/barrel (barrels corrected to 60°F)
G_{fg}	=	Specific gravity of the tank flash gas, where air = 1. A suggested default value for G_{fg} is 1.22
G_{oil}	=	API gravity of stock tank oil at 60°F
P_{sep}	=	Pressure in separator (or other vessel directly upstream), in pounds per square inch gauge
T_{sep}	=	Temperature in separator (or other vessel directly upstream of the tank), °F
A	=	0.0362 for G_{oil} <= 30°API, or 0.0178 for G_{oil} > 30°API
B	=	1.0937 for G_{oil} <= 30°API, or 1.187 for G_{oil} > 30°API
C	=	25.724 for G_{oil} <= 30°API, or 23.931 for G_{oil} > 30°API

Sometimes one or more emissions source vents may be connected to the storage tank. In such cases the emissions from these sources will be commingled with the emissions from the storage tank. In addition, two phase separators directly upstream of the storage tank may not have a vortex breaker. This can lead to channeling of natural gas from the separator to the storage tank. All these multiple scenarios mean that only Method 1 could potentially capture such miscellaneous sources connected to the storage tank. If, however, Method 1 is performed at a time when say the separator is not vortexing then even Method 1 may not capture the emissions from the miscellaneous emissions sources connected to the storage tank. Hence there is no single method that can identify these variations in storage tank emissions that represent multiple sources. These data are available from two recent studies provided by the Texas Commission on Environmental Quality (2009) and the Texas Environment Research Consortium (2009) that highlight this fact. A potential option to correct such scenarios where other emissions sources are connected to the storage tank or if the separator is vortexing is to use multipliers on emissions estimated from Methods 1 and 2 above. Two such potential multipliers are as below,

(i) The emissions for sales oil less than 45 API gravity can be multiplied by 3.87

(ii) The emissions for sales oil equal to or greater than 45 API gravity can be multiplied by 5.37

Details on the development of these multipliers are available in Appendix E.

Dump Valve Emissions Estimation

Storage tank vented emissions quantification could include the emissions that result from a gas-liquids separator liquid dump valve malfunction. Liquid dump or scrubber dump valves open periodically to reduce the accumulation of liquids in the separator. Scrubber dump valves can get stuck open due to debris preventing it from closing properly. In such a case, natural gas from the separator is lost through the dump valve ultimately passing through the storage tank's atmospheric vent. Equation 18, below, can be used to account for storage tank emissions with improperly closed scrubber dump valves.

$$E_{s,i} = (CF_n \times E_n \times T_n) + (E_n \times (8760 - T_n))$$ **Equation 18**

where,

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each storage tank in cubic feet.

E_n = Storage tank emissions as determined in calculation methods 1, 2, or 5 (with wellhead separators) of this section of the TSD during time T_n in cubic feet per hour.

T_n = Total time the dump valve is not closing properly in the calendar year in hours. T_n is estimated by maintenance or operations records (records) such that when a record shows the valve to be open improperly, it is assumed the valve was open for the entire time period preceding the record starting at either the beginning of the calendar year or the previous record showing it closed properly within the calendar year. If a subsequent record shows it is closing properly, then assume from that time forward the valve closed properly until either the next record of it not closing properly or, if there is no subsequent record, the end of the calendar year.

CF_n = Correction factor for tank emissions for time period T_n is 3.87 for sales oil less than 45 API gravity. Correction factor for tank emissions for time period Tn is 5.37 for sales oil equal to or greater than 45 API gravity. Correction factor for tank emissions for time period T_n is 1.0 for periods when the dump valve is closed.

E_t = Storage tank emissions as determined in calculation methods 1, 2, or 3 of this section of the TSD at maintenance or operations during the time the dump valve is closing properly (ie.8760-T_n) in cubic feet per hour.

Transmission Storage Tanks:

Storage tanks in the onshore natural gas transmission segment typically store the condensate from the scrubbing of pipeline quality gas. The volume of condensate is typically low in comparison to the volumes of hydrocarbon liquids stored in the upstream segments of the industry. Hence the emissions from condensate itself in the transmission segment are insignificant. However, scrubber dump valves often get stuck due to debris in the condensate and can remain open resulting in natural gas loss via the open dump valve. If the scrubber dump valve is stuck and leaking natural gas to the tank then the emissions will be visibly significant and will not subside to inconspicuous volumes. If the scrubber dump valve functions normally and shuts completely after the condensate has been dumped then the storage tank emissions should subside and taper off to insignificant quantities; this will happen because once the condensate has flashed the dissolved natural gas there will not be significant emissions from the storage tank. If persistent and significant emissions are detected then a measurement of those emissions may be required using a temporary meter or ultrasonic devices that can detect and measure the emissions in a non-invasive way.

Storage tank vapors captured using vapor recovery systems or sent to flares will have to be accounted for in the above methods.

13. Well testing venting and flaring

During well testing the well usually is flowing freely and the produced hydrocarbons are typically vented and/ or flared. A gas to oil ratio is often determined when conducting well testing. This information can be reliably used to estimate emissions from well testing venting using Equation 19 below:

$$E_{s,n} = GOR * FR \quad D \qquad \textbf{Equation 19}$$

where,

$E_{s,n}$	=	Annual volumetric natural gas emissions from well testing in cubic feet under actual conditions
GOR	=	Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities
FR	=	Flow rate in barrels of oil per day for the well being tested
D	=	Number of days during the year the well is tested

When well testing emissions are sent to a flare then the emissions estimated above should be adjusted to reflect the combustion emissions.

14. Associated gas venting and flaring

Often times when onshore petroleum production fields are located in a remote location, the associated gas produced is sent to a vent or flare. This is because the associated natural gas is stranded gas, meaning that it is not economical to send the usually low volumes to the market via a pipeline system. Also, gas from producing wells may sometimes be routed to a

vent or a flare due to system upset conditions or for maintenance of field equipment. In such cases the emissions can be estimated using the volume of oil produced and the corresponding gas to oil ratio as following;

Vented associated natural gas emissions can be estimated using Equation 20 below:

$$E_{a,n} = GOR * V \qquad \textbf{Equation 20}$$

where,

$E_{a,n}$	=	Annual volumetric natural gas emissions from associated gas venting under actual conditions, in cubic feet
GOR	=	Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities
V	=	Total volume of oil produced in barrels in the calendar year.

When well testing emissions are sent to a flare then the emissions estimated above will have to be adjusted to reflect the combustion emissions.

15. Hydrocarbon liquids dissolved CO_2

Onshore petroleum production that uses EOR with CO_2 injection results in the production of petroleum that has significant amounts of CO_2 dissolved in it. This CO_2 is usually separated from the liquid petroleum component, and re-injected in a closed loop system (although this CO_2 might be eventually recovered when the EOR operation at the site is closed). However, the liquid portion of petroleum still contains dissolved CO_2, since separation usually takes place at higher than ambient pressure. Most of this CO_2 is then released in a storage tank where the CO_2 flashes out of the liquid hydrocarbons. But even after this stage some amount of CO_2 remains entrapped in the liquid hydrocarbons and is lost to the atmosphere during the transportation and processing phases.

The amount of CO_2 retained in hydrocarbon liquids after flashing in tanks can be determined by taking quarterly samples to account for retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. The emissions from this hydrocarbon dissolved CO2 can be estimated using Equation 21 below:

$$Mass_{s,\,CO2} = S_{hl} * V_{hl} \qquad \textbf{Equation 21}$$

where,

$Mass_{s,\,CO2}$	=	Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids beyond tankage, in metric tons.
S_{hl}	=	Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

V_{hl} = Total volume of hydrocarbon liquids produced in barrels in the calendar year.

16. Produced water dissolved CO_2

EOR operations may use water injection techniques to pressurize the reservoir and drive the hydrocarbons containing CO_2 through the reservoir and up the production well. This water, like the liquid petroleum, contains dissolved CO_2, since CO_2 readily dissolves in water. This produced water is re-circulated for injection into the reservoir. However, often it may be sent through tankage to avoid a two phase flow of CO_2 and water through the injection pumps. In such cases the CO_2 dissolved in the water is flashed to the atmosphere in the storage tank.

These emissions can be determined similar to hydrocarbon dissolved CO_2 by sampling the water on a periodic basis. To determine retention of CO_2 in produced water immediately downstream of the separator where hydrocarbon liquids and produced water are separated the following equation can be used.

$$Mass_{s,\,CO2} = S_{pw} * V_{pw} \qquad \textbf{Equation 22}$$

where,

$Mass_{s,\,CO2}$ = Annual CO_2 emissions from CO_2 retained in produced water beyond tankage, metric tons.

S_{pw} = Amount of CO_2 retained in produced water in metric tons per barrel, under standard conditions.

V_{pw} = Total volume of produced water produced in barrels in the calendar year.

EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir in a closed loop system without any leakage to the atmosphere could be exempted from reporting.

17. Well venting for liquids unloading

There are three potential methods to estimate well venting emissions from liquids unloading. Method 1 requires installation of a flow meter temporarily for developing an emissions factor. Method 2 requires a transient pressure spike engineering analysis across the vent pipe during one well unloading event. Method 3 uses an engineering calculation method that uses the well's physical parameters to estimate emissions. Each of the three options is discussed below.

Method 1:

For each unique well tubing diameter and producing horizon/formation combination in each gas producing field where gas wells are vented to the atmosphere to expel liquids

accumulated in the tubing, a recording flow meter can be installed on the vent line used to vent gas from the well (e.g. on the vent line off the separator or a storage tank). An emissions factor can be estimated as an average flow rate per minute of venting calculated for each unique tubing diameter and producing horizon/formation combination in each producing field. The emission factor can be applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, multiplied by the number of minutes of venting of all wells of the same tubing diameter and producing horizon/formation combination in that field. A new factor can be determined periodically to track field declining formation pressure and flow potential.

Method 2:

For each unique well tubing diameter and producing horizon/formation combination in each gas producing field where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, an engineering analysis of the transient pressure spike across the vent line for well unloading events can be conducted. An emissions factor as an average flow rate per minute of venting can then be calculated through such an analysis. This emissions factor can be applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, multiplied by the number of minutes of venting all wells of the same tubing diameter and producing horizon/formation combination in that field. A new emission factor can be determined periodically to track field declining formation pressure and flow potential. Emissions from well venting for liquids unloading can be calculated using Equation 23 below:

$$E_{s,n} = T * X * EF \qquad \textbf{Equation 23}$$

where,

$E_{s,n}$	=	Annual natural gas emissions at standard conditions
T	=	Amount of time of well venting
X	=	Concentration of GHG i in gas vented.
EF	=	Emission factor developed using the transient pressure spike

For wells that have a plunger lift installed on a timer or programmable logic controller that vent to the atmosphere and automatically closes the vent valve when the plunger is received at the well head, an equation calculating the volume of gas in the tubing string calculated at sales pipeline pressure can be used. This equation is unique for each category of wells with the same well depth and tubing size. The emissions factor can be estimated by multiplying the tubing cross-sectional area by the tubing string length from wellhead to the bottom resting location of the plunger, corrected for sales line pressure and average gas flowing temperature.

Method 3:

The Natural Gas STAR Lessons Learned – Installing Plunger Lift Systems in Gas Wells (available at <http://epa.gov/gasstar/documents/ll_plungerlift.pdf>) provides an engineering estimation method in its Appendix. This method uses physical characteristics of the well that are usually well known. Using this method, emissions from well venting for liquids unloading can be calculated using Equation 24 below:

$$E_{a,n} = \{(0.37\times10^{-3}) * CD^2 * WD * SP * V\} + \{SFR*(HR-T)*Z\}$$ **Equation 24**

where,

$E_{s,n}$	=	Annual natural gas emissions at actual conditions, in cubic feet/year
0.37×10^{-3}	=	*{pi(3.14)/4}/{(14.7*144) psia converted to pounds per square feet}*
CD	=	Casing diameter (inches)
WD	=	Well depth (feet)
SP	=	Shut-in pressure (psig)
V	=	Number of vents per year
SFR	=	Average sales flow rate of gas well in cubic feet per hour
HR	=	Hours that the well was left open to the atmosphere during unloading
T	=	1 hour for average well to blowdown casing volume at shut-in pressure for wells without plunger lift assist; 0.5 hour for average well to blowdown tubing volume at sales line pressure when using plunger lift assist.
Z	=	If HR is less than 1.0 then Z is equal to 0. If HR is greater than or equal to 1.0 then Z is equal to 1.

For details on the time taken to blowdown a casing and tubing to unload a well, see "Change to Rule Equation W-7: Time to Vent the Casing Gas from Well Liquids Unloading" in the rulemaking docket (EPA-HQ-OAR-2009-0923)

18. Gas well venting during well completions and workovers

There are two methods to estimate emissions from gas well venting during well completions and workovers. Method 1 requires the installation of a recording flow meter on the vent line to the atmosphere or to a flare. Method 2 is an engineering calculation for flow based on the pressure drop across the well choke for subsonic and sonic flow. Method 3 uses the production of the well to determine emissions.

Method 1:

A recording flow meter can be installed on the vent line to the atmosphere or to a flare during each well completion or workover event. This one time reading can be extrapolated to yearly emissions based on the time taken for completion or workover and the number of times the

well is worked over (if more than once per year). Such emissions factors can be developed for representative wells in a field on a yearly basis. During periods when gas is combusted in a flare, the carbon dioxide quantity can be determined from the gas composition with an adjustment for combustion efficiency. This method can also be used when phase separation equipment is used and requires the installation of a recording flow meter on the vent line to the atmosphere or to a flare.

Emissions from gas well venting during well completions and workovers can be calculated using Equation 25 below:

$$E_{a,n} = T * FR - EnF - SG \qquad \textbf{Equation 25}$$

where,

$E_{a,n}$	=	Annual natural gas vented emissions at ambient conditions in cubic feet
T	=	Cumulative amount of time in hours of well venting during the reporting period
FR	=	Flow rate in cubic feet per hour, under ambient conditions
EnF	=	Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job. If the fracture process did not inject gas into the reservoir, then EnF is 0. If injected gas is CO_2 then EnF is 0.
SG	=	Volume of natural gas in cubic feet at standard conditions that was recovered into a sales pipeline. If no gas was recovered for sales, SG is 0.

Method 2:

Using pressures measured upstream and downstream of the well choke, the average flow rate across the choke can be calculated. Using engineering judgment and the total time that flow across the choke is occurring, the total volume to the atmosphere or a flare during the back-flow period can be estimated. This one time reading can be extrapolated to yearly emissions based on the time taken for completion or workover and the number of times the well is worked over (if more than once per year). Such emissions factors can be developed for representative wells in a field on a yearly basis.

Emissions from gas well venting during well completions and workovers can be calculated using Equation 26 for subsonic flow and Equation 27 for sonic flow below:

$$FR = 1.27 \times 10^5 * A * \sqrt{3430 * T_u * \left(\frac{P_2}{P_1}\right)^{1.515} - \left(\frac{P_2}{P_1}\right)^{1.758}} \qquad \textbf{Equation 26}$$

where,

FR	=	Average flow rate in cubic feet per hour, under subsonic flow conditions.
A	=	Cross sectional area of orifice (m^2).
P_1	=	Upstream pressure (psia).
T_u	=	Upstream temperature (degrees Kelvin).
P_2	=	Downstream pressure (psia).
3430	=	Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$	=	Conversion from m^3/second to ft^3/hour.

$$FR = 1.27 \square 10^5 * A * \sqrt{187.08 * T_u}$$ **Equation 27**

where,

FR	=	Average flow rate in cubic feet per hour, under sonic flow conditions.
A	=	Cross sectional area of orifice (m^2).
T_u	=	Upstream temperature (degrees Kelvin).
187.08	=	Constant with units of $m^2/(sec^2 * K)$.
$1.27*10^5$	=	Conversion from m^3/second to ft^3/hour.

Method 3:

A quick and least burdensome method to determine emissions from well venting during completions and workovers is to use the daily gas production rate to estimate emissions using Equation 28 below:

$$E_{a,n} = \sum_f V_f * T_f$$ **Equation 28**

where,

$E_{a,n}$	=	Annual natural gas emissions in cubic feet at actual conditions from gas well venting during well completions and workovers without hydraulic fracturing.
f	=	Total number of well completions without hydraulic fracturing in a field.
V_f	=	Average daily gas production rate in cubic feet per hour of each well completion without hydraulic fracturing. This is the total annual gas production volume divided by total number of hours the wells produced to the sales line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

T_f = Time each well completion without hydraulic fracturing was venting in hours during the year.

19. Onshore production combustion emissions

The combustion process is well understood in terms of GHG emissions. The use of emissions factors is reliable if the quantity and type of fuel combustion is known. The alternative is to use combustion emissions stack monitors, which are cost prohibitive and may not be considered appropriate for onshore production. Onshore production segment does not meter its fuel, since most of the equipment in the field is located upstream of the lease meter. However, requiring meters at every single well site to measure fuel volume is not feasible in terms of cost. Hence, the use of heat rating of the equipment along with the hours of operations is the most feasible approach to estimate the amount of fuel consumed. Using the emissions factors approach, GHG emissions from combustion equipment can be estimated using broadly two methods; fuel specific emissions factors and equipment specific fuel factors. Fuel specific emissions factors are related to a particular type of fuel in use and do not take into account the type of equipment (e.g. whether internal or external combustion equipment). The advantage of this type of approach is that if the fuel volume for a facility is known then there is no need to identify the particular equipment that is combusting it. The disadvantage in this method though is that it does not take into account the differing levels of efficiency between different types of equipment. On the other hand, equipment specific emissions factors take into account the efficiency levels of each equipment type corresponding with the type of fuel it combusts. However, the disadvantage of using equipment specific emissions factors is that fuel consumption has to be known at an equipment level. Both fuel specific and equipment specific emissions factors are available form the API Compendium and EPA AP-42 documents.

20. Natural gas distribution combustion emissions

The combustion emissions from natural gas distribution result mainly from inline gas heaters, small compressors, etc. Heaters are used to prevent natural gas dropping below the dew point (where liquids, mainly water, might condense) or to maintain the temperature of gas let-down in pressure from high pressure transmission pipelines to low pressure distribution gate station metering systems. The Joule-Thompson effect causes gas temperature to drop when the gas is suddenly expanded across a valve or orifice. Thus, transmission pressure gas at, for example 1000 psig and ambient temperature of 70°F can drop well below freezing when depressurized to 100 psig. This gas may be heated to a temperature above so-called "dry" gas dew point or a range consistent with distribution gate station meter calibrations. These are usually small sources of emissions and may not contribute significantly to the total emissions from the distribution segment. However, some natural gas distribution systems operate compressor stations that are similar in size and operations to the natural gas transmission or gas storage systems. These compressor stations may have significant emissions and could be captured under combustion emissions reporting.

c. Leak detection and leaker emission factors

For leaks from standard components such as connectors, valves, meters, etc. emissions can be estimated by conducting an equipment leak detection program and applying a leaker emissions factor to those sources found to be emitting. This option may be considered over direct measurement (e.g., high flow sampler) to avoid the capital cost in measurement equipment and labor hours to conduct measurement. Estimating emissions using leaker emission factors is more accurate than population factors because leaker factors are applied to leaks once they are identified. Since equipment leaks occur randomly within a population of components, determining the number of actual leaking component improves the emissions estimate. Equation 29, below, can be used for this purpose.

$$E_{s,i} = GHG_i * \sum_x EF_X * T_x \qquad \textbf{Equation 29}$$

where,

$E_{s,i}$	=	Annual total volumetric GHG emissions at standard conditions from each equipment leak source in cubic feet.
x	=	Total number of this type of emissions source found to be leaking during T_x.
EF_E	=	Leaker emission factor for specific sources
GHG_i	=	For onshore petroleum and natural gas production facilities and onshore natural gas processing facilities,, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; other segments GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2.
T_x	=	The total time the component was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

Leaker emissions factors are available for specific sources for onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, liquefied natural gas storage facilities, liquefied natural gas import and export facilities, and natural gas distribution facilities. These leaker emissions factors and a discussion on their development are available in Appendix F.

d. Population Count and Emission Factors.

For equipment leaks that are geographically dispersed or where the cost burden is an issue, emissions can be estimated using the population count of emissions sources and a

corresponding population emissions factor. This option may be considered over direct measurement to avoid the cost of purchasing a high volume sampler, screening device, and the labor hours to use both. Such an option may be most feasible for emissions sources with gas content greater than 10 percent CH_4 plus CO_2 by weight since otherwise the emissions factors may overestimate overall GHG emissions. The disadvantage of using population factors is that it will only provide an estimate of potential emissions, not actual emissions. It will also not provide any trends in changes in emissions over time, since the only variable is equipment/ component count, which in most operations does not change significantly. Hence, petroleum and natural gas operators who are voluntarily reducing emissions by conducting periodic leak detection and repair will end up reporting more emissions than is actually occurring in their operations. Emissions from all sources listed in this paragraph of this section can be calculated using Equation 30.

$$E_{s,i} = Count * EF * GHG_i * T \qquad \textbf{Equation 30}$$

where,

$E_{s,i}$	=	Annual total volumetric GHG emissions at standard conditions from each equipment leak source category
$Count$	=	Total number of this type of emission source at the facility
EF	=	Population emission factor for specific sources listed in Appendix F.
GHG_i	=	for onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities GHG_i equals 1
T	=	Total time the specific source associated with the equipment leak was operational in the reporting period, in hours

Population emissions factors are available for specific sources for onshore petroleum and natural gas production facilities, onshore natural gas processing facilities, onshore natural gas transmission compression facilities, underground natural gas storage facilities, liquefied natural gas storage facilities, liquefied natural gas import and export facilities, and natural gas distribution facilities. These population emissions factors and a discussion on their references are available in Appendix G.

e. Method 21

This is the authorized method for detecting volatile organic carbon (VOC) emissions under Title 40 CFR. The method specifies the performance of a portable VOC emission detection instrument with a probe not exceeding one fourth inch outside diameter, used to slowly circumscribe the entire component interface where a leak could occur. The probe must be maintained in close proximity to (but not touching) the interface; otherwise it could be damaged by rotating shafts or plugged with ingested lubricants or greases. In most cases, it can be no more than 1 centimeter away from the leak interface. Method 21 does not specify

leak definitions; they are defined within specific subparts of the Title 40 CFR. Method 21 also allows certain alternative equipment leak detection methods, such as soap solutions (where the leaking source is below the boiling point and above the freezing point of the soap solution, does not have areas open to the atmosphere that the soap solution cannot bridge, and does not have signs of liquid leakage). Method 21 does not specify any emissions mass or volumetric quantification methods, but only specifies an emissions concentration expressed in parts per million of combustible hydrocarbons in the air stream of the instrument probe. This leak detection data has been used by state emission inventories with "leaker" factors developed by the Synthetic Organic Chemicals Manufacturing Industry (SOCMI)[8] to estimate the quantity of VOC emissions. SOCMI factors were developed from petroleum refinery and petrochemical plant data using Method 21.

Method 21 instrumentation technology has been used for over 30 years to detect leaks. The approach uses gas concentration measurement of air and combustible gas drawn into the tip of a probe manually circumscribed on or within one centimeter along the entire potential seal surface or center of a vent to detect equipment leaks. This original practice is required for certain regulated components that are reachable with the hand-held leak detection instrument used while standing on the ground or fixed platform accessible by stairs (i.e. does not require climbing ladders, standing on stools or use of bucket-lift trucks to access components). In a study conducted by API at seven California refineries[9] with over five years of measured data (11.5 million data points), it was found that 0.13 percent of the components contributed over 90 percent of the controllable emissions (i.e. equipment leaks or vented emissions that can be mitigated once detected). Given the fact that only a small number of sources contribute to the majority of emissions, it is important for this final rule to detect and quantify leaking sources beyond the scope of Method 21.

Performance standards for remote leak sensing devices, such as those based on infrared (IR) light imaging, or laser beams in a narrow wavelength absorbed by hydrocarbon gases, were promulgated in the general provisions of EPA 40 CFR Part 60. This alternate work practice (AWP) permits leak detection using an instrument which can image both the equipment and leaking gas for all 40 CFR 60 subparts that require monitoring under LDAR.

In a typical Method 21 program, the costs of conducting emissions detection remain the same during each recurring study period. This is because the determination of whether a potential source is emitting or not is made only after every regulated source is screened for emissions as described above. The OVA/TVA requires the operator to physically access the emissions source with the probe and thus is much more time intensive than using the optical gas imaging instrument. Optical gas imaging instruments were found to be more cost effective for leak detection for this reporting rule as these instruments are able to scan hundreds of source components quickly, including components out of reach for an OVA/TVA.

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[8] EPA (1995). *Protocol for Equipment Leak Emission Estimates.* Research Triangle Park, NC. Publication No. EPA-453/R-95-017. Online at: http://www.epa.gov/ttnchie1/efdocs/equiplks.pdf

[9] Hal Taback Company *Analysis of Refinery Screening Data*, American Petroleum Institute, Publication Number 310, November 1997.

Although leak detection with Method 21 or the AWP in their current form in conjunction with leaking component emission factors may not be the best suited for all mandatory reporting, the principle could potentially be adopted for estimating emissions from minor sources such as equipment leaks from components. Emissions can be detected from sources (including those not required under Method 21, i.e. not within arm's reach) using AWP procedures for the optical gas imaging instrument, and applying leaker emissions factors available from studies conducted specifically with methane emissions in its scope. This will be easier for industry to adapt to and also avoid the use of Synthetic Organic Chemical Manufacturing Industry correlation equations or leak factors developed specifically for different industry segments (i.e. petroleum refineries and chemical plants). This method will also result in the estimation of real emissions, as opposed to potential emissions from population emissions factor calculations.

f. Portable VOC Detection Instruments for Leak Measurement

As discussed above under Method 21, portable VOC detection instruments do not quantify the volumetric or mass emissions. They quantify the concentration of combustible hydrocarbon in the air stream induced through the maximum one fourth inch outside diameter probe. Since these small size probes rarely ingest all of the emissions from a component leak, they are used primarily for equipment leak detection. EPA provides emissions quantification guidelines, derived from emissions detection data, for using portable VOC detection devices. One choice of instrument emissions detection data is referred to as "leak/no-leak," where equipment is determined to be leaking when the portable instrument indicates the provided leak definition. Different leak definitions are specified within the subparts of the Clean Air Act. Subpart KKK of 40 CFR Part 60 defines "leakers" for natural gas processing facilities as components with a concentration of 10,000 ppm or more when measured by a portable leak detection instrument. Components that are measured to be less than 10,000 ppm are considered "not leaking." Hence, these quantification tables have a "no-leak" emission factor for all components found to have emissions rates below the leak definition, and "pegged" emission factors for all components above the leak definition. Alternatively, the "stratified" method has emission factors based on ranges of actual leak concentrations below, at and above the leak definition. Portable leak detection instruments normally peg at 10,000 ppm, and so are unsuitable for use with the "stratified" quantification factors.

g. Mass Balance for Quantification

There are mass balance methods that could be considered to calculate emissions for a reporting program. This approach would take into account the volume of gas entering a facility and the amount exiting the facility, with the difference assumed to be emitted to the atmosphere. This is most often discussed for emissions estimation from the transportation segment of the industry. For transportation, the mass balance is often not recommended because of the uncertainties surrounding meter readings and the large volumes of throughput relative to equipment leaks. The mass balance approach may, however, be feasible in cases where the volume of emissions is significantly large and recognizable as meter readings. One such source is an acid gas recovery unit where the volume of CO_2 extracted from natural gas

is significant enough to be registered in a compositional difference of the natural gas and can be determined using mass balance.

h. Gulf Offshore Activity Data System program (GOADS)

The Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) conducts a comprehensive activity data collection effort under its Gulf Offshore Activity Data System program (GOADS) in compliance with 30 CFR 250.302 through 304. This requires all petroleum and natural gas production platforms located in the Federal Gulf of Mexico (GoM) to report their activities to BOEMRE once in every three to four years. The activity data reported includes counts of emissions sources, volumes of throughputs from several pieces of equipment, fuel consumption by combustion devices, and parametric data related to certain emissions sources such as glycol dehydrators. This activity data is then converted into emissions estimates by BOEMRE and reported subsequently by BOEMRE. The BOEMRE summary report provides estimates of GHG emissions in the GoM as well as a detailed database of emissions from each source on platform in the GoM. The EPA could potentially use this data reported by the GOADS program. However, since the data has historically been collected once every three to four years, EPA will not receive new emissions information for every reporting period. This means that between BOEMRE reporting periods if a new platform is commissioned, an old platform is de-commissioned, new equipment is installed on existing platforms, or operating levels of platforms change then this information will not get recorded and reported for periods when BOEMRE GOADS is not being conducted. This issue however, can be resolved by requiring new platforms to use the most recent GOADS methods to estimate emissions and other reporters to adjust their emissions annually based on the time each platform was operating in comparison to the GOADS reporting year. Finally, the BOEMRE GOADS program does not collect information from platforms in the GoM under State jurisdiction, as well as platforms in the Pacific and Alaskan coasts. These platforms not under GOADS purview will not have existing data to report if GOADS reporting were to be adopted by EPA. Nevertheless, a reporting rule can potentially require non-GOADS platforms to adopt the GOADS methodology to calculate emissions. If BOEMRE discontinues or delays their GOADS, then platform operators under a reporting rule using GOADS may refer to the most recently published version of the GOADS program instructions to continue reporting.

i. Additional Questions Regarding Potential Monitoring Methods

There are several additional issues regarding the potential monitoring methods relevant to estimating equipment leak and vented emissions from the petroleum and natural gas industry.

i. Source Level Equipment Leak Detection Threshold

This document does not indicate a particular equipment leak definition or detection threshold requiring emissions measurement. This is because different equipment leak detection instruments have different levels and types of detection capabilities, i.e. some instruments provide a visual image while others provide a digital value on a scale (not necessarily

directly related to mass emissions). Hence the magnitude of actual emissions can only be determined after measurement. This, however, may not serve the purpose of a reporting rule, which is to limit the burden by focusing only on significant sources of emissions. A facility can have hundreds of small emissions (as low as 3 grams per hour) and it might not be practical to measure all of them for reporting.

There are, however, two possible approaches to overcome this issue, as follows; provide an instrument performance standard such that any source determined to be emitting per the instrument is considered an emissions source, or provide a threshold value for the emitter such that any source below the threshold magnitude is not considered an emitter.

Instrument Performance Standards

Performance standards can be provided for equipment leak detection instruments and usage such that all instruments follow a minimum common detection threshold. Alternatively, the AWP to Detect Leaks from Equipment standards for optical gas imaging instruments recently adopted by EPA can potentially be proposed. In such a case, all detected emissions from components subject to the final rule may require measurement and reporting. This avoids the necessity of specifying performance standards.

The EPA Alternative Work Practice (AWP) promulgated the use of optical gas imaging instruments that can detect in some cases emissions as small as 1 gram per hour. The AWP requires technology effectiveness of emissions statistically equivalent to 60 grams/hour on a bi-monthly screening frequency, i.e. the technology should be able to routinely detect all emissions equal to or greater than 60 grams/hour. EPA determined by Monte Carlo simulation that 60 grams/hour leak rate threshold and bi-monthly monitoring are equivalent to existing work practices (Method 21). To implement the technology effectiveness, the AWP requires that the detection instrument meet a minimum detection sensitivity mass flow rate. For the purposes of the proposed supplemental rule, such a performance standard could be adapted for the detection of natural gas emissions with methane as the predominant component (it should be noted that Method 21 is specifically meant for VOCs and HAPs and not for methane).

Equipment Leak Threshold

One alternative to determining an emission source is to provide a mass emissions threshold for the emitter. In such a case, any source that emits above the threshold value would be considered an emitter. For portable VOC monitoring instruments that measure emission concentrations a concentration threshold equivalent to a mass threshold can be provided. However, the concentration measurement is converted to an equivalent mass value using SOCMI correlation equations, which were developed from petroleum refinery and petrochemical plant data. In the case of an optical imaging instrument, which does not provide the magnitude of emissions, either concentration or mass emissions, quantification would be required using a separate measurement instrument to determine whether a source is an emitter or not. This could be very cost prohibitive for the purposes of this rule.

ii. Duration of Equipment Leaks

Equipment leaks by nature occur randomly within the facility. Therefore, there is no way of knowing when a particular source started emitting. If the potential monitoring method requires a one time equipment leak detection and measurement, then assumptions will have to be made regarding the duration of the emissions. There are several potential options for calculating the duration of emissions. If a component leak is detected, total emissions from each source could be quantified under one of the following three scenarios: 1) if a facility conducts one comprehensive leak survey each reporting period, applicable component leaker emissions factors could be applied to all specific component emissions sources and emissions quantified based on emissions occurring for an entire reporting period; 2) if a facility conducts two comprehensive leak surveys during a single reporting period, applicable component leaker emissions factors could be applied to all component emissions sources. If a specific emission source is found not leaking in the first survey but leaking in the second survey, emissions could be quantified from the date of the first leak survey conducted in the same reporting period forward through the remainder of the reporting period. If a specific emissions source is found leaking in the first survey but is repaired and found not leaking in the second survey, emissions could be quantified from the first day of the reporting period to the date of the second survey. If a component is found leaking in both surveys, emissions could be quantified based on an emission occurring for an entire reporting period; 3) if a facility conducts multiple comprehensive leak surveys during the same reporting period, applicable component leaker emissions factors could be applied to component emissions sources. Each specific source found leaking in one or more surveys is quantified for the period from a prior finding of no leak (or beginning of the reporting period) to a subsequent finding of no leak (or end of the reporting period). If a component is found leaking in all surveys, emissions could be quantified based on an emissions occurring for an entire reporting period.

iii. Equipment Leak and Vented Emissions at Different Operational Modes

If a reporting program relies on a one time or periodic measurement, the measured emissions may not account for the different modes in which a particular technology operates throughout the reporting period. This may be particularly true for measurements taken at compressors. Compressor leaks are a function of the mode in which the compressor is operating: i.e. offline pressurized, or offline de-pressurized. Typically, a compressor station consists of several compressors with one (or more) of them on standby based on system redundancy requirements and peak delivery capacity. When a compressor is taken offline it may be kept pressurized with natural gas or de-pressurized. When the compressor is offline and kept pressurized, equipment leaks and vented emissions result from closed blowdown valves and reciprocating compressor rod packing leaks, respectively. When the compressor is offline and depressurized, emissions result from leaking isolation valves. When operating, compressor vented emissions result from compressor seals or rod packing and other components in the compressor system. In each of the compressor modes, the resultant equipment leak and vented emissions are significantly different. One potential approach to account for these varying levels of equipment leak and vented emissions is to have operators measure all compressors in each operating mode once a reporting period. Operators would

also need to report the time for which the compressor is in the different modes. The disadvantages to this approach is that it will increase the reporting burden because measurements will have to be taken at each mode of compressor operation in each reporting period and the time that the equipment is in various operational modes would also have to be tracked. In addition, it is not feasible to require operators to take compressors off-line every year to conduct measurements in offline pressurized and depressurized modes. One alternative approach is to report compressor emissions in the mode the compressors are found, also known as reporting compressor emissions "as-is". The reporters could then determine emission factors for each mode and apply them to the period of time each compressor was not in the mode it was measured in for the reporting period. Since most compressors would be found in the, pressurized, operating mode, reporters could be required to measure each compressor in an offline mode less frequently (e.g. every three reporting periods) to ensure sufficient data points are collected in the less common offline modes.

A similar issue exists with tanks where the operating conditions change more often than for compressors. The amount of throughput through tanks varies continuously as new hydrocarbon liquids are introduced and stored liquids are withdrawn for transportation. Unlike other equipment, the operational level of tanks cannot be categorized into a fixed and limited number of modes. This makes it all the more challenging to characterize emissions from storage tanks. One option is to require operators to use best judgment and characterize a few different modes for the storage tanks and make adjustments to the monitored emissions accordingly.

iv. Natural Gas Composition

When measuring equipment leaks and vented emissions using the various measurement instruments (high volume sampler, calibrated bags, and meters) or using engineering estimation for vented emissions, only flow rate is measured or calculated and the individual CH_4 and CO_2 emissions are estimated from the natural gas mass emissions using natural gas composition appropriate for each facility. For this purpose, the monitoring methodologies discussed above would require that facilities use existing gas composition estimates to determine CH_4 and CO_2 components of the natural gas emissions (acid gas recovery units, flare stacks, and storage tank vented emissions are an exception to this general rule). These gas composition estimates are assumed to be available at facilities. But this may or may not be a practical assumption for reporting. In the absence of gas composition, periodic measurement of the required gas composition for speciation of the natural gas mass emissions into CH_4 and CO_2 mass emissions could be a potential option.

In addition, GHG components of natural gas may change significantly in the facilities during the reporting period and different sources in the same facility may be emitting different compositions of natural gas. This is most prevalent in onshore production, offshore production and natural gas processing facilities. One potential option is to apply an average composition across all emissions sources for the reporting facility. Another option is to apply specific composition estimates across similar streams in the same facility. For example, in processing, the natural gas composition is similar for all streams upstream of the de-methanizer. The same is true of all equipment downstream of the de-methanizer overhead.

For onshore production and offshore production monthly or quarterly samples can be taken to account for the variation in natural gas being produced from different combinations of production wells throughout the reporting period.

v. **Physical Access for Leak Measurement**

All emissions measurement techniques require physical access to the leaking source. The introduction of remote leak detection technologies based on infrared (IR) light absorption by hydrocarbon gas clouds from atmospheric leaks makes leak detection quicker and possible for sources outside of arms reach from the ground or fixed platforms. Leaks from flanges, valve stems, equipment covers, etc. are generally smaller than emissions from vents. Component leaks are expensive to measure where they are not accessible within arms reach from the ground or a fixed platform. For these inaccessible sources, the use of emission factors for emissions quantification may be appropriate. Vent stacks are often located out of access by operators for safety purposes, but may represent large emission sources. Where emissions are detected by optical gas imaging instruments, emissions measurement may be cost-effective using the following source access techniques:

- É Short length ladders positioned on the ground or a fixed platform where OSHA regulations do not require personnel enclosure and the measurement technique can be performed with one hand;
- É Bucket trucks can safely position an operator within a full surround basket allowing both hands to be used above the range of ladders or for measurement techniques requiring both hands;
- É Relatively flat, sturdy roofs of equipment buildings and some tanks allow safe access to roof vents that are not normally accessible from fixed platforms or bucket trucks;
- É Scaffolding is sometimes installed for operational or maintenance purposes that allow access to emission sources not normally accessible from the ground, fixed platforms and out of reach of bucket trucks.

7. Procedures for Estimating Missing Data

It is possible that some companies would be missing data necessary to quantify annual emissions. In the event that data are missing, potential procedures to fill the data gap are outlined below and are organized by data type.

In general, although there is always the possibility of using a previous periods' data point to replace missing data in the current reporting period, this is not ideal since varying operating conditions can dramatically impact emissions estimates. Where using previous reporting periods' data are not desirable, then a reporting rule might require 100% data availability. In other words, there would be no missing data procedures provided. If any data were identified as missing, then there would be an opportunity to recollect the emissions data over the course of the current reporting period.

a. Emissions Measurement Data

Measured data can be collected by trained engineers using a high volume sampler, meter, or calibrated bag. Over the course of the data collection effort, some of the measured emissions rates could get lost temporarily or permanently due to human error, or storage errors such as lost hard-drives and records. If measured data is missing then the field measurement process may have to be repeated within the reporting period. If this proves to be impossible and the company clearly certifies that they lost the data and can justify not repeating the survey within the given reporting period, then the previous reporting period's data could be used to estimate equipment leaks from the current reporting period.

b. Engineering Estimation Data

Engineering estimations rely on the collection of input data to the simulation software or calculations. A potential procedure for missing input data is outlined below for each type of input parameter.

- Operations logs. If operating logs are lost or damaged for a current reporting period, previous reporting period's data could be used to estimate emissions. Again, using previous reporting periods' data are not as desirable as there could be significant differences from period to period based on operating conditions.
- Process conditions data. Estimating vented emissions from acid gas removal vent stacks, blowdown vent stacks, dehydrator vents, natural gas driven pneumatic valve bleed devices, natural gas driven pneumatic pumps, and storage tanks requires data on the process conditions (e.g., process temperature, pressure, throughputs, and vessel volumes). If, for any reason, these data are incomplete or not available for the current reporting period, field operators or engineers could recollect data wherever possible. If this data cannot be collected, then relevant parameters for estimation of emissions can be used from previous reporting period. However, where possible current reporting period parameters should be used for emissions estimation due to the reasons listed above.

c. Emissions Estimation Data for Storage Tanks and Flares

Emissions from storage tanks and flares might require a combination of both direct measurement and engineering estimation to quantify emissions. In such cases the storage tank emissions calculation requires the measurement of "emissions per throughput" data. If this data is missing then the previous reporting periods' estimate of "emissions per throughput" measured data could be used with current period throughput of the storage tank to calculate emissions.

Calculating emissions from flares requires the volume of flare gas measured using a meter. If these data are missing then the flare gas in the current reporting period could be estimated by scaling the flare gas volume from previous reporting period by adjusting it for current period throughput of the facility.

d. Emissions Estimation Data Using Emissions Factors

If population emissions factors are used then the only data required is activity data. In such a case missing data should be easily replaceable by undertaking a counting exercise for locations from which the data is missing. Alternatively, previous reporting period activity data can be used to fill in missing data. However, if facility and/ or equipment modifications have resulted in increase or decrease in activity data count then this may not be a feasible approach.

If leaker emissions factors are used then activity data will have to be collected using some form of equipment leak detection. In such case, missing data may not be easily replaceable. Previous period reported activity data may be used but it may not be representative of current period emissions. A detection survey to replace missing data may be warranted.

8. QA/QC Requirements

a. Equipment Maintenance

Equipment used for monitoring, both emissions detection and measurement, should be calibrated on a scheduled basis in accordance with equipment manufacturer specifications and standards. Generally, such calibration is required prior to each monitoring cycle for each facility. A written record of procedures needed to maintain the monitoring equipment in proper operating condition and a schedule for those procedures could be part of the QA/QC plan for the facility.

An equipment maintenance plan could be developed as part of the QA/QC plan. Elements of a maintenance plan for equipment could include the following:

- Conduct regular maintenance of monitoring equipment.
    - Keep a written record of procedures needed to maintain the monitoring system in proper operating condition and a schedule for those procedures;
    - Keep a record of all testing, maintenance, or repair activities performed on any monitoring instrument in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring instrument and records of any corrective actions associated with a monitor's outage period.

b. Data Management

Data management procedures could be included in the QA/QC Plan. Elements of the data management procedures plan are as follows:

- Check for temporal consistency in production data and emission estimate. If outliers exist, can they be explained by changes in the facility's operations, etc.?

- A monitoring error is probable if differences between annual data cannot be explained by:
  - É Changes in activity levels,
  - É Changes concerning monitoring methodology,
  - É Changes concerning change in equipment,
  - É Changes concerning the emitting process (e.g. energy efficiency improvements).[10]

- Determine the "reasonableness" of the emission estimate by comparing it to previous year's estimates and relative to national emission estimate for the industry:
  - Comparison of emissions by specific sources with correction for throughput, if required,
  - Comparison of emissions at facility level with correction for throughput, if required,
  - Comparison of emissions at source level or facility level to national or international reference emissions from comparable source or facility, adjusted for size and throughput,
  - Comparison of measured and calculated emissions.[10]

- Maintain data documentation, including comprehensive documentation of data received through personal communication:
  - Check that changes in data or methodology are documented

c. Calculation checks

Calculation checks could be performed for all reported calculations. Elements of calculation checks could include:

- Perform calculation checks by reproducing a representative sample of emissions calculations or building in automated checks such as computational checks for calculations:
  - Check whether emission units, parameters, and conversion factors are appropriately labeled,
  - Check if units are properly labeled and correctly carried through from beginning to end of calculations,
  - Check that conversion factors are correct,
  - Check the data processing steps (e.g., equations) in the spreadsheets,
  - Check that spreadsheet input data and calculated data are clearly differentiated
  - Check a representative sample of calculations, by hand or electronically,
  - Check some calculations with abbreviated calculations (i.e., back of the envelope checks),

[10] Official Journal of the European Union, August 31, 2007. Commission Decision of 18 July 2007, "Establishing guidelines for the monitoring and reporting of GHG emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council. Available at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2007:229:0001:0085:EN:PDF.

- Check the aggregation of data across source categories, business units, etc.,
- When methods or data have changed, check consistency of time series inputs and calculations.[11]

9. Reporting Procedure

(a) The facilities that cross the potential threshold for reporting could report the following information to EPA:

(1) Emissions monitored at an aggregate source level for each facility, separately identifying those emissions that are from standby sources. In several onshore natural gas processing plants CO_2 is being capture for Enhanced Oil Recovery operations. Therefore, these CO_2 emissions may have to be separately accounted for in the reporting.

(2) Activity data, such as the number of sources monitored, for each aggregated source type level for which emissions will be reported.

(3) The parameters required for calculating emissions when using engineering estimation methods.

In addition, the following reporting requirements could be considered for a reporting rule;

(b) Equipment leaks by nature occur randomly within the facility, therefore, where emissions are reported on an annual basis, it may not be possible to determine *when* the equipment leaks began. As discussed in more detail in Section (I)(ii) of the TSD, under these circumstances, annual emissions could be determined assuming that the equipment leaks were continuous from the beginning of the reporting period or from the last recorded not leaking in the current reporting period and until the equipment leak is repaired or the end of the reporting period.

(c) Due to the point-in-time nature of direct measurements, reports of annual emissions levels should take into account equipment operating hours according to standard operating conditions and any significant operational interruptions and shutdowns, to convert direct measurement to an annual figure.

10. Verification of Reported Emissions

As part of the data verification requirements, the owner or operator could submit a detailed explanation of how company records of measurements are used to quantify equipment leaks and vented emissions measurement within 7 days of receipt of a written request from EPA or from the applicable State or local air pollution control agency (the use of electronic mail can be made acceptable).

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[11] U.S. EPA 2007. Climate Leaders, Inventory Guidance, Design Principles Guidance, Chapter 7 "Managing Inventory Quality". Available at http://www.epa.gov/climateleaders/documents/resources/design_princ_ch7.pdf.

Appendix A: Segregation of Emissions Sources using the Decision Process

The tables provided in this appendix represent the outcome of the decision process used to identify a starting list of potential sources that were evaluated for inclusion in the final rule. The decision process was applied to each emission source in the natural gas segment of the U.S. GHG Inventory. The petroleum onshore production segment has emission sources that either are equivalent to their counter-parts in the natural gas onshore production segment or fall in the exclusion category. Petroleum transportation was not analyzed further due to the level of emissions and refineries are treated separately in Subpart Y.

Sources Contributing to 80% of Equipment Leaks and Vented Emissions from Each Industry Segment

Source	Offshore Production	Onshore Production	Processing	Transmission	Storage	LNG Storage	LNG Import and Export	Distribution
Separators		4%						
Meters/Piping		4%						
Small Gathering Reciprocating Comp.		2%						
Pipeline Leaks		7%						
CBM Powder River		2%						
Pneumatic Device Vents		43%	0.26%	12%	13%			
Gas Pneumatic Pumps		9%	0.49%					
Dehydrator Vents	2%	3%	3%					
Well Clean Ups (LP Gas Wells)/ Blowdowns		7%						
Plant/Station/ Platform Fugitives	4%		5%		16%	14%	3%	
Reciprocating Compressors			48%	40%	45%	54%	14%	
Centrifugal Compressors	22%		16%	8%	6%	19%	4%	
Acid Gas Removal Vents			2%					
Vessel Blowdowns/Venting			6%					
Routine Maintenance/Upsets - Pipeline venting				10%				
Station venting				8%			2%	
M&R (Trans. Co. Interconnect)				4%				
Pipeline Leaks Mains								36%
Services								16%
Meter/Regulator(City Gates)								37%
Residential Customer Meters								
Flare stacks	1%							
Non-pneumatic pumps	0.03%							
Open ended lines	0.005%							
Pump seals	0.41%							
Storage tanks	50%							
Wellhead fugitive emissions					4%			
Well completions		0.0004%						
Well workovers		0.04%						

NOTE: Pink cells represent sources that were included over riding the decision tree process. Blue cells represent sources that are not present in the respective segments. Green cells represent sources that are not explicitly identified in the U.S. GHG Inventory; however, these sources may potentially be found in the respective segments. Blank cells are sources in the U.S. GHG Inventory.

Inventory of Methane Emissions from Natural Gas Systems

PRODUCTION OFFSHORE	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Amine gas sweetening unit	0.2	80	0.01%	0.0001%	NE	c	c	a	n
Boiler/heater/burner	0.8	332	0.05%	0.0002%		c	d	a	n
Diesel or gasoline engine	0.01	6	0.001%	0.000004%		c	d	a	n
Drilling rig	3	1,134	0.17%	0.001%		c	d	a	n
Flare	24	9,583	1.47%	0.01%		c	c	b	n
Centrifugal Seals	358	144,547	22%	0.10%		a	a	a	b
Connectors	0.8	309	0.05%	0.0002%		b	b	b	b
Flanges	2.38	960	0.15%	0.001%		b	b	b	b
OEL	0.1	32	0.005%	0.00002%		b	b	b	b
Other	44	17,576	2.70%	0.01%		b	b	b	b
Pump Fugitive	0.5	191	0.03%	0.0001%		b	b	a	b
Valves	19	7,758	1%	0.01%		b	b	b	b
Glycol dehydrator	25	9,914	2%	0.01%		c	c	b	n
Loading operation	0.1	51	0.01%	0.00004%		c	d	a	n
Separator	796	321,566	49%	0.23%		c	c	b	b
Mud degassing	8	3,071	0.47%	0.002%		c	d	a	n
Natural gas engines	191	77,000	12%	0.05%					
Natural gas turbines	3	1,399	0.22%	0.001%					
Pneumatic pumps	7	2,682	0.41%	0.002%		c	b	a	b
Pressure/level controllers	2	636	0.10%	0.0005%		c	b	a	b
Storage tanks	7	2,933	0.45%	0.002%		c	c	a	n
VEN exhaust gas	121	48,814	8%	0.03%		c	c	b	n

NOTES: Leak Detection: a – Yes and cost effective; b – Yes but cost burden c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

PRODUCTION ONSHORE	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Normal Fugitives									
Gas Wells									
Non-associated Gas Wells (less Unconventional)	2,682	1,083,539	2%	0.77%	376784	b	b	b	b
Unconventional Gas Wells	69	27,690	0.06%	0.02%	35440	a	b	b	b
Field Separation Equipment					0				
Heaters	1,463	591,023	1%	0.42%	89720	a	b	b	b
Separators	4,718	1,906,206	4%	1%	247919	b	b	b	b
Dehydrators	1,297	524,154	1%	0.37%	37925	a	b	b	b
Meters/Piping	4,556	1,840,683	4%	1%	315487	b	b	b	b
Gathering Compressors					0				
Small Reciprocating Comp.	2,926	1,182,062	2%	1%	28490	a	a	b	b
Large Reciprocating Comp.	664	268,133	0.54%	0.19%	112	a	a	b	b
Large Reciprocating Stations	45	18,178	0.04%	0.01%	14	a	a	b	b
Pipeline Leaks	8,087	3,267,306	7%	2%	392624	b	b	b	n
Vented and Combusted									
Drilling and Well Completion									
Completion Flaring	0	188	0.00%	0.00%	597	c	c	c	n
Well Drilling	96	38,946	0.08%	0.03%	35600	c	c	a	y
Coal Bed Methane									
Powder River	2,924	1,181,246	2%	1%	396920	c	c	a	n
Black Warrior	543	219,249	0.44%	0.16%		c	c	a	n
Normal Operations									
Pneumatic Device Vents	52,421	21,178,268	43%	15%		c	b	a	b
Chemical Injection Pumps	2,814	1,136,867	2%	0.81%		c	b	a	b
Kimray Pumps	11,572	4,674,913	9%	3%		c	b	a	n
Dehydrator Vents	3,608	1,457,684	3%	1%		c	c	a	n
Condensate Tank Vents									
Condensate Tanks without Control Devices	1,225	494,787	1%	0.35%		c	c	a	b
Condensate Tanks with Control Devices	245	98,957	0.20%	0.07%		c	d	a	b
Compressor Exhaust Vented									
Gas Engines	11,680	4,718,728	9%	3%					
Well Workovers									
Gas Wells	47	18,930	0.04%	0.01%		c	d	b	y
Well Clean Ups (LP Gas Wells)	9,008	3,639,271	7%	3%		c	d	a	n
Blowdowns									
Vessel BD	31	12,563	0.03%	0.01%		c	d	a	n
Pipeline BD	129	52,040	0.10%	0.04%		c	d	a	b
Compressor BD	113	45,648	0.09%	0.03%		c	d	a	n
Compressor Starts	253	102,121	0.20%	0.07%		c	d	a	n
Upsets									
Pressure Relief Valves	29	11,566	0.02%	0.01%		c	d	b	n
Mishaps	70	28,168	0.06%	0.02%		c	d	b	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

GAS PROCESSING PLANTS	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Normal Fugitives									
Plants	1,634	660,226	5%	0.47%		a	a	b	b
Recip. Compressors	17,351	7,009,755	48%	5%		a	a	b	b
Centrifugal Compressors	5,837	2,358,256	16%	2%		a	a	b	b
Vented and Combusted									
Normal Operations									
Compressor Exhaust									
Gas Engines	6,913	2,792,815	19%	2%					
Gas Turbines	195	78,635	1%	0.06%					
AGR Vents	643	259,592	2%	0.18%		c	c	a	n
Kimray Pumps	177	71,374	0.49%	0.05%		c	b	a	b
Dehydrator Vents	1,088	439,721	3%	0.31%		c	c	a	n
Pneumatic Devices	93	37,687	0.3%	0.03%		c	b	a	b
Routine Maintenance									
Blowdowns/Venting	2,299	928,900	6%	1%		c	d	a	n

Notes:

Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

TRANSMISSION	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Fugitives									
Pipeline Leaks	166	67,238	0.17%	0.05%		a	c	a	n
Compressor Stations (Transmission)									
Station	5,619	2,270,177	6%	2%		a	a	b	b
Recip Compressor	38,918	15,722,907	40%	11%		a	a	b	b
Centrifugal Compressor	7,769	3,138,795	8%	2%		a	a	b	b
M&R (Trans. Co. Interconnect)	3,798	1,534,238	4%	1%		a	a	b	b
M&R (Farm Taps + Direct Sales)	853	344,646	1%	0.25%		b	b	b	b
Vented and Combusted									
Normal Operation									
Dehydrator vents (Transmission)	105	42,329	0.11%	0.03%		c	c	a	n
Compressor Exhaust									
Engines (Transmission)	10,820	4,371,314	11%	3%					
Turbines (Transmission)	61	24,772	0.06%	0.02%					
Generators (Engines)	529	213,911	0.55%	0.15%					
Generators (Turbines)	0	60	0.0002%	0.00004%					
Pneumatic Devices Trans + Stor									
Pneumatic Devices Trans	11,393	4,602,742	12%	3%		c	b	a	b
Routine Maintenance/Upsets									
Pipeline venting	9,287	3,752,013	10%	3%		c	d	a	b
Station venting Trans + Storage									
Station Venting Transmission	7,645	3,088,575	8%	2%		c	d	a	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

STORAGE	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Fugitives									
Compressor Stations (Storage)									
Station	2,801	1,131,492	16%	1%		a	a	b	b
Recip Compressor	8,093	3,269,454	45%	2%		a	a	b	n
Centrifugal Compressor	1,149	464,354	6%	0.33%		a	a	b	n
Wells (Storage)	695	280,891	4%	0.20%		a	a	b	y
Vented and Combusted									
Normal Operation									
Dehydrator vents (Storage)	217	87,514	1%	0.06%		c	c	a	n
Compressor Exhaust									
Engines (Storage)	1,092	441,108	6%	0.31%					
Turbines (Storage)	9	3,680	0.05%	0.003%					
Pneumatic Devices Trans + Stor									
Pneumatic Devices Storage	2,318	936,324	13%	1%		c	b	a	b
Station venting Trans + Storage									
Station Venting Storage	1,555	628,298	9%	0.45%		c	d	a	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

LNG STORAGE	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
LNG Storage									
LNG Stations	552	222,824	14%	0.16%		b	b	b	b
LNG Reciprocating Compressors	2,084	842,118	54%	1%		b	b	b	b
LNG Centrifugal Compressors	715	288,756	19%	0.21%		b	b	b	b
LNG Compressor Exhaust									
LNG Engines	172	69,632	5%	0.05%					
LNG Turbines	1	261	0.02%	0.0002%					
LNG Station venting	306	123,730	8%	0.09%		c	d	a	n

LNG IMPORT AND EXPORT TERMINALS	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
LNG Import Terminals									
LNG Stations	22	8,880	3%	0.01%		b	b	b	b
LNG Reciprocating Compressors	105	42,347	14%	0.03%		b	b	a	b
LNG Centrifugal Compressors	27	10,820	4%	0.01%		b	b	a	b
LNG Compressor Exhaust									
LNG Engines	586	236,647	78%	0.17%					
LNG Turbines	3	1,370	0.45%	0.001%					
LNG Station venting	12	4,931	2%	0.004%		c	d	a	n

Notes: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.
Export Terminals are not currently included in the U.S. GHG Inventory, therefore they were not included in this analysis. There is currently only one export terminal, located in Alaska.

DISTRIBUTION	Total Emissions Nationally (MMcf/year)	Tonnes CO2e/ Year	% of Sector Emissions	% of total Inventory Emissions	Activity Factors	Leak Detection	Direct Measurement	Engineering Estimate	Accesible Source
Normal Fugitives									
Pipeline Leaks									
Mains - Cast Iron	9,222	3,725,675	14%	3%		a	b	b	n
Mains - Unprotected steel	6,515	2,632,209	10%	2%		a	b	b	n
Mains - Protected steel	1,422	574,529	2%	0.41%		a	b	b	n
Mains - Plastic	6,871	2,775,759	10%	2%		a	b	b	n
Total Pipeline Miles			36%	7%					
Services - Unprotected steel	7,322	2,957,970	11%	2%		a	b	b	n
Services Protected steel	2,863	1,156,473	4%	1%		a	b	b	n
Services - Plastic	315	127,210	0.47%	0.09%		a	b	b	n
Services - Copper	47	19,076	0.07%	0.01%		a	b	a	n
Total Services			16%	3%					
Meter/Regulator (City Gates)			37%	7%					
M&R >300	5,037	2,034,986	7%	1%	3,198	a	a	b	b
M&R 100-300	10,322	4,170,101	15%	3%	12,325	b	b	b	b
M&R <100	249	100,480	0.37%	0.07%	6,587	a	c	b	b
Reg >300	5,237	2,115,726	8%	2%	3,693	a	a	b	b
R-Vault >300	25	9,976	0.04%	0.01%	2,168	a	a	b	b
Reg 100-300	4,025	1,625,929	6%	1%	11,344	b	b	b	b
R-Vault 100-300	8	3,247	0.01%	0.002%	5,097	a	c	b	b
Reg 40-100	306	123,586	0.45%	0.09%	33,578	b	b	b	b
R-Vault 40-100	23	9,115	0.03%	0.01%	29,776	b	b	b	b
Reg <40	17	6,690	0.02%	0.005%	14,213	b	b	b	b
Customer Meters									
Residential	5,304	2,142,615	8%	2%	37017342	b	b	a	y
Commercial/Industry	203	81,880	0.30%	0.06%	4231191	b	b	a	y
Vented									
Rountine Maintenance									
Pressure Relief Valve Releases	63	25,346	0.09%	0.02%		c	d	b	n
Pipeline Blowdown	122	49,422	0.18%	0.04%		c	d	a	n
Upsets									
Mishaps (Dig-ins)	1,907	770,405	3%	1%		c	d	b	n

NOTES: Leak Detection: a – Yes and cost effective; b – Yes but cost burden; c - No. Cost effectiveness based on expert judgment.
Direct Measurement: a – Accurate and cost effective; b – Accurate but cost burden; c – Questionable; d – No direct measurement.
Engineering Estimate: a – Exists; b – does not exist.
Accessible Source: y – Yes; n – No; b – Both.

Appendix B: Development of revised estimates for four U.G. GHG Inventory emissions sources

Well Completion and Workover Venting

This discussion describes the methods used to estimate total U.S. methane emissions from well completion and workover venting. For the purposes of this estimate, it is assumed that all unconventional wells are completed with hydraulic fracturing of tight sand, shale or coal bed methane formations (i.e. completions involving high rate, extended back-flow to expel fracture fluids and sand proppant, which also leads to greater gas venting or flaring emissions than conventional well completions). It is understood that not all unconventional wells involve hydraulic fracturing, but some conventional wells are hydraulically fractured, which is assumed to balance the over-estimate.

► *Estimate the Number of Gas Wells Completed*

The data in Exhibit B-1 was extracted from EPA (2008)[12]. The unconventional well column only includes CBM wells and shale gas wells, but does not include tight sands formations because that data is not readily available either publically or in the U.S. Inventory. Thus, this analysis underestimates the activity associated with unconventional well completions and workovers.

Exhibit B-1. 2007 Natural Gas Wells

Year	Approximate Number of Onshore Unconventional Gas Wells	Approximate Number of Onshore Conventional Gas Wells	Total Number of Gas Wells (both conventional and unconventional)
2006	35,440	375,601	411,041
2007	41,790	389,245	431,035

Exhibit B-1 was used to calculate that there was a net increase of 19,994 wells (both conventional and unconventional) between 2006 and 2007. Each of these wells is assumed to have been completed over the course of 2006. EPA (2008) also estimates that 35,600 gas wells were drilled in 2006. This includes exploratory wells, dry holes, and completed wells. EPA (2008) also indicates that 19,994 of those natural gas wells were drilled and completed. The difference between the 35,600 drilled and 19,994 new wells is 15,606 wells, which we assume are replaced for shut-in or dry holes. This analysis assumed that 50% of those remaining 15,606 wells were completed. Thus, the total number of gas well completions, both conventional and unconventional, was estimated to be 27,797 wells in 2006.

$$19\,994 wells + (50\% \times (35\,600 wells - 19\,994 wells)) = 27{,}797 wells$$

That is 78% of the total gas wells drilled in 2006. We assumed this same percentage of completed wells applies to the year 2007. EPA (2008) estimates 37,196 gas wells were

[12] EPA.. (2008) *U.S. Inventory of Greenhouse Gas Emissions and Sinks: 1990 – 2007*. Available online at: <http://epa.gov/climatechange/emissions/usgginv_archive.html>.

drilled in 2007, so applying this completion factor, 78% of 37,196 wells equals 29,043 gas wells completed in 2007.

► *Estimate the Number of Conventional and Unconventional Well Completions*

Exhibit B-1 shows a net increase of 6,350 unconventional wells from 2006 to 2007. This is 32% of the 19,994 net increase in all wells over that period. It was assumed that 32% of the estimated 29,043 well completions in 2007 (see previous section) were unconventional wells. The remaining gas well completions were assumed to be conventional wells. These results are summarized in Exhibit B-2. This analysis also assumed that all unconventional wells require hydraulic fracture upon completion. Because these completions and workovers only account for CBM wells and shale gas wells, it is a significant underestimate since tight sands formations are omitted.

Exhibit B-2. 2007 Completions Activity Factors

2007 Conventional Well Completions	19,819
2007 Unconventional Well Completions	9,224

►*Estimate the Number of Conventional and Unconventional Well Workovers*

GRI (1996)[13] provides activity data for 1992 on conventional workovers. It reported that 9,324 workovers were performed with 276,014 producing gas wells. This activity data was projected to 2007 using the ratio of 2007 producing gas wells to 1992 producing gas wells; as shown in Exhibit 3:

Exhibit B-3. Calculation of 2007 Conventional Workover Activity Factor

$$2007 Conventional Workovers = 1992 Conventional Workovers \times \frac{2007 Gas Wells}{1992 Gas Wells}$$

$$2007 Conventional Workovers = 9{,}324 workovers \times \frac{431{,}035 wells}{276{,}014 wells}$$

Unconventional gas wells were assumed to be re-fractured once every 10 years. Thus, the number of unconventional gas well workovers was 10% of the existing unconventional well count in 2007.

The resulting activity factors for conventional and unconventional gas well workovers are summarized in Exhibit B-4.

Exhibit B-4. Summary of 2007 Workover Activity Factors

[13] GRI. *Methane Emissions from the Natural Gas Industry*. 1996. Available online at: <http://epa.gov/gasstar/tools/related.html>.

2007 Conventional Well Workovers	$9{,}324 workovers \times \frac{431{,}035 wells}{276{,}014 wells} =$	14,569
2007 Unconventional Well Workovers	$10\% \times 41{,}790 wells =$	4,179

►*Estimate the Emission Factor for Conventional Well Completions*
GRI (1996) estimated that conventional well completions emit 0.733 Mcf of methane each. GRI (1996) assumed that all completion flowback was flared at 98% combustion efficiency and the produced gas was 78.8% methane by volume. This analysis estimated the amount of gas sent to the flare by dividing the reported GRI factor by the 2% un-combusted gas. The resulting emission factor for conventional well completions was **36.65 Mcf of methane/completion**.

►*Estimate the Emission Factor for Conventional Well Workovers*
The GRI (1996) emission factor for well workovers was accepted for this analysis. That emission factor is **2.454 Mcf of methane/workover** for conventional wells.

►*Estimate the Emission Factor for Unconventional Well Completions*
The emission factor for unconventional well completions was derived using several experiences presented at Natural Gas STAR technology transfer workshops.

One presentation[14] reported that the emissions from all unconventional well completions were approximately 45 Bcf using 2002 data. The emission rate per completion can be back-calculated using 2002 activity data. API *Basic Petroleum Handbook*[15] lists that there were 25,520 wells completed in 2002. Assuming Illinois, Indiana, Kansas, Kentucky, Michigan, Missouri, Nebraska, New York, Ohio, Pennsylvania, Virginia, and West Virginia produced from low-pressure wells that year, 17,769 of those wells can be attributed to onshore, non-low-pressure formations. The Handbook also estimated that 73% (or 12,971 of the 17,769 drilled wells) were gas wells, but are still from regions that are not entirely low-pressure formations. The analysis assumed that 60% of those wells are high pressure, tight formations (and 40% were low-pressure wells). Therefore, by applying the inventory emission factor for low-pressure well cleanups (49,570 scf/well-year[1]) approximately 5,188 low-pressure wells emitted 0.3 Bcf .

$$40\% \times 12\,971 wells \times \frac{49\,570 scf}{well} \times \frac{1 Bcf}{10^9 scf} \approx 0.3 Bcf$$

The remaining high pressure, tight-formation wells emitted 45 Bcf less the low-pressure 0.3 Bcf, which equals 44.7 Bcf. Since there is great variability in the natural gas sector and the resulting emission rates have high uncertainty; the emission rate per unconventional (high-pressure tight formation) wells were rounded to the nearest thousand Mcf.

[14] EPA. *Green Completions*. Natural Gas STAR Producer's Technology Transfer Workshop. September 21, 2004. Available online at: <http://epa.gov/gasstar/workshops/techtransfer/2004/houston-02.html>.
[15] API. *Basic Petroleum Data Handbook*. Volume XXIV, Number 1. February, 2004.

$$\frac{44.7 Bcf}{60\% \times 12{,}971 wells} \times \frac{10^6 Mcf}{Bcf} \approx 6{,}000 Mcf / completion$$

The same Natural Gas STAR presentation[14] provides a Partner experience which shares its recovered volume of methane per well. This analysis assumes that the Partner recovers 90% of the flowback. Again, because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was estimated only to the nearest thousand Mcf – 10,000 Mcf/completion.

A vendor/service provider of "reduced emission completions" shared its experience later in that same presentation[14] for the total recovered volume of gas for 3 completions. Assuming that 90% of the gas was recovered, the total otherwise-emitted gas was back-calculated. Again, because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was rounded to the nearest hundred Mcf – 700 Mcf/completion.

The final Natural Gas STAR presentation[16] with adequate data to determine an average emission rate also presented the total flowback and total completions and re-completions. Because of the high variability and uncertainty associated with different completion flowbacks in the gas industry, this was rounded to the nearest 10,000 Mcf – 20,000 Mcf/completion.

This analysis takes the simple average of these completion flowbacks for the unconventional well completion emission factor: **9,175 Mcf/completion**.

►*Estimate the Emission Factor for Unconventional Well Workovers ("re-completions")*
The emission factor for unconventional well workovers involving hydraulic re-fracture ("re-completions") was assumed to be the same as unconventional well completions; calculated in the previous section.

►*Estimate the Total National Emissions (disregarding reductions)*
The estimated activity factors were multiplied by the associated emission factors to estimate the total emissions from well completions and workovers in the U.S. for 2007. This does not reflect reductions due to control technologies such as flares or bringing portable treatment units onsite to perform a practice called "reduced emission completions." The results are displayed in Exhibit B-5 below.

Exhibit B-5. Summary of Flowback: U.S. Completion and Workover Venting 2007

Activity	Activity Factor	Emission Factor	Total U.S. Emissions
Conventional Gas Well Completions	19,819 completions	36.65 Mcf/completion	~0.7 Bcf
Conventional Gas Well Workovers	14,569 workovers	2.454 Mcf/workover	<< 1 Bcf

[16] EPA. *Reducing Methane Emissions During Completion Operations*. Natural Gas STAR Producer's Technology Transfer Workshop. September 11, 2007. Available online at: <http://epa.gov/gasstar/documents/workshops/glenwood-2007/04_recs.pdf>.

Unconventional Gas Well Completions	9,224 completions	9,175 Mcf/completion	~85 Bcf
Unconventional Gas Well Workovers	4,179 workovers	9,175 Mcf/workover	~38. Bcf
Note: The emission factors and calculated emissions as presented in this table were rounded independently.		**TOTAL:**	**~120 Bcf**

► *Estimate the Volume of Emissions That Are Not Flared*

Some states regulate that completion and re-completion (workover) flowbacks must be flared or recovered. Industry representatives have shared with EPA that flaring of completions and workovers is required in Wyoming; however, it is not required in Texas, New Mexico, and Oklahoma. EPA assumed that no completions were flared in the Texas, New Mexico, and Oklahoma, then took the ratio of unconventional wells in Wyoming to the unconventional wells in all four sample states to estimate the percentage of well completions and workovers that are flared. EPA assumed that this sample was indicative of the rest of the U.S. This ratio was estimated to be approximately 51%.

The portion of flared natural gas was deducted from the results of Exhibit B-5 so that only the vented portion of natural gas from well completions and workovers was estimated. It then converted these natural gas emissions to methane emissions using an average methane content in produced natural gas of 78.8% by volume. The results are in Exhibit B-6, below.

Exhibit B-6. Summary of Methane Emissions: U.S. Completion and Workover Venting 2007

Activity	Unmitigated Flowback	Natural Gas Vented	Methane Vented
Conventional Gas Well Completions	~0.7 Bcf	~0.37 Bcf	~0.29 Bcf
Conventional Gas Well Workovers	<< 1 Bcf	<< 1 Bcf	<< 1 Bcf
Unconventional Gas Well Completions	~85 Bcf	~43 Bcf	~34 Bcf
Unconventional Gas Well Workovers	~38. Bcf	~19 Bcf	~14 Bcf
Note: The emission factors and calculated emissions as presented in this table were rounded independently.		**TOTAL:**	**~48 Bcf**

The final resulting methane emissions from well completions and workovers is **48 Bcf**. This estimate does not include hydraulic fracturing due to completions and workovers of gas wells in tight sands formations. Tight sands wells are not tracked by the U.S. Inventory and may substantially increase this estimate of unconventional well completions and workovers. A 2008 INGAA study[17] estimated that, in fact, approximately twice as many unconventional wells were completed than this analysis and approximately twice as many unconventional wells exist, 10% of which may require workover. This increase in activity is due to the inclusion of tight sands formations. If this analysis were to account for that activity level, not only would the number of hydraulic fractures increase substantially, but also the distribution of wells that are required to flare by law would be shifted such that only 15% of hydraulic

[17] INGAA Foundation Inc.. Availability, *Economics, And Production Potential of North American Unconventional Natural Gas Supplies*. November 2008.

fracture flowbacks would be estimated to be flared. Using INGAA's estimates of activity, emissions would increase to 141 Bcf.

Well Blowdown Venting for Liquid Unloading

This discussion describes the methods used to estimate total U.S. methane emissions from low-pressure well blowdowns for liquid unloading.

► *Estimate the Fraction of Conventional Wells that Require Liquid Unloading*

This analysis assumed that the survey of 25 well sites conducted by GRI (1996) for the base year 1992 provides representative data for the fraction of conventional wells requiring unloading. That is, 41.3% of conventional wells required liquid unloading.

► *Calculate Emissions per Blowdown*

This analysis used a fluid equilibrium calculation to determine the volume of gas necessary to blow out a column of liquid for a given well pressure, depth, and casing diameter. The equation for this calculation is available in an EPA, Natural Gas STAR technical study[18]. The equation is displayed in Exhibit B-7.

Exhibit B-7. Well Blowdown Emissions for Liquid Unloading

$$V_v = \left(0.37 \times 10^{-6}\right) \times D^2 \times h \times P$$

where,

V_v	=	Vent volume (Mcf/blowdown)
D	=	casing diameter (inches)
h	=	well depth (feet)
P	=	shut-in pressure (psig)

A combination of GASIS[19] and LASSER[20] databases provided well depth and shut-in pressures for a sample of 35 natural gas basins. The analysis assumed an average casing diameter of 10-inches for all wells in all basins.

► *Estimate the Annual Number of Blowdowns per Well that Require Unloading*

For wells that require liquid unloading, multiple blowdowns per year are typically necessary. A calibration using the equation in the previous section was performed using public data for the shared experiences of two Natural Gas STAR Partners.

One Partner reported that it recovered 4 Bcf of emissions using plunger lifts with "smart" automation (to optimize plunger cycles) on 2,200 wells in the San Juan basin[21]. Using the

[18] EPA. *Installing Plunger Lift Systems in Gas Wells: Lessons Learned from Natural Gas STAR Partners*. October, 2003. Available online at: <http://epa.gov/gasstar/documents/ll_plungerlift.pdf>.
[19] DOE. *GASIS, Gas Information System*. Release 2 – June 1999.
[20] LASSER™ database.
[21] EPA. *Natural Gas STAR Partner Update: Spring 2004*. Available online at: <http://epa.gov/gasstar/documents/partner-updates/spring2004.pdf>.

data for San Juan basin in the equation in Exhibit B-6 required approximately 51 blowdowns per well to match the 4 Bcf of emissions.

Another Partner reported that it recovered 12 MMcf of emissions using plunger lifts on 19 wells in Big Piney[18]. Using information for the nearest basin in the equation in Exhibit B-6 required approximately 11 blowdowns per well to match the 12 MMcf of emission.

The simple average of 31 blowdowns per well requiring liquid unloading was used in the analysis to determine the number of well blowdowns per year by basin.

► *Estimate the Percentage of Wells in Each Basin that are Conventional*
GASIS and LASSER provided approximate well counts for each basin and GRI provided the percentage of conventional wells requiring liquid unloading for 35 sample basins. However, many of those basins contain unconventional wells which will not require liquid unloading. EIA posts maps that display the concentration of conventional gas wells in each basin[22], the concentration of gas wells in tight formations by basin[23], and the concentration of coal bed methane gas wells by basin[24]. These maps were used to estimate the approximate percentage of wells that are conventional in each basin. These percentages ranged from 50% to 100%.

►*Estimate Emissions from 35 Sample Basins*
The total well counts for each basin were multiplied by the percentage of wells estimated to be conventional for that basin to estimate the approximate number of conventional wells in each of the basins. The resulting conventional well counts were multiplied by the percentage of wells requiring liquid unloading, as estimated by the GRI survey (41.3%). The number of wells in each basin that require liquid unloading were multiplied by an average of 31 blowdowns/well to determine the number of well blowdowns for each basin. The emissions per blowdown, as calculated using the equation in Exhibit B-6, were then multiplied by the number of blowdowns for each basin to estimate the total well venting emissions from each of the 35 sample basins due to liquid unloading. Using the GRI estimate that the average methane content of production segment gas is 78.8% methane by volume, the total methane emissions from the sample of 35 basins were calculated to be 149 Bcf.

►*Extrapolate Sample Data to Entire U.S.*
The sample of 35 gas well basins represented only 260,694 conventional gas wells. EPA's national inventory[25] estimated that there were 389,245 conventional gas wells in 2007. The emission estimates were extrapolated to the entire nation by the ratio of the conventional gas wells. The final resulting emissions from gas well venting due to liquid unloading were estimated to be **223 Bcf**.

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[22] EIA. *Gas Production in Conventional Fields, Lower 48 States*. Available online at: <http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm>.
[23] EIA. *Major Tight Gas Plays, Lower 48 States*. Available online at: <http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm>.
[24] EIA. *Coal Bed Methane Fields, Lower 48 States*. Available online at: <http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm>.
[25] EPA. *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2006*. 2007. Available online at http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

This estimate does not include emission reductions from control methods such as plunger lifts, plunger lifts with "smart" automation, or other artificial lift techniques.

Appendix C: Development of threshold analysis

As the main text has pointed out the petroleum and natural gas sector includes hundreds, and in some cases thousands, of operators, many of them with few emission sources as well as ones with over 100 emission sources. Requiring all operators to report would impose a large burden on the industry and also on EPA. A rule-of-thumb, substantiated by survey work, is that 80 percent of the emissions come from 10 percent of the analysis. Therefore, a threshold analysis was performed so that the large emitters would be identified and small insignificant emitters could be excluded from the reporting requirement.

Threshold Analysis for Onshore Production

The following points lay out the methodology for the threshold analysis for the onshore petroleum and natural gas production segment

- The threshold analysis for onshore (including EOR) production sector estimated the equipment leaks, vented emissions, and combustion emissions per unique operator per basin.
- The oil and gas production volumes per operator per basin were obtained from the HPDI™ database 2006. The total onshore oil and gas production process and combustion (CH_4 and CO_2) emissions estimated in the U.S. GHG Inventory 2006 were apportioned to each operator based on the oil or gas production volumes.
- The U.S. GHG Inventory emissions estimates for the following sources were revised: gas well hydraulic fracture completion venting, gas well liquids unloading venting, and gas well workover venting following hydraulic fracture. Natural Gas STAR emission reductions reported by partners from these sources are higher than the current inventory emission estimates. As a result emissions from these sources are currently under-estimated in the inventory. The methodology used to revise these emissions estimates can be found in Appendix B. In addition, emissions from storage tanks vented and flared emissions are believed to be under estimated in the U.S. GHG Inventory. EPA independently estimated the storage tank emissions using publicly available data described in docket memo "Analysis of Tank Emissions" (EPA-HQ-OAR-2009-0923-0002). EPA's estimated emissions from onshore production storage tanks may be as high as 75 billion cubic feet (Bcf) as compared with the 12 Bcf estimate provided in the 2006 inventory. In addition, the threshold analysis does not account for several sources that are not represented in the U.S. GHG Inventory such as associated gas venting and flaring, well testing venting and flaring and gas well hydraulic fracture completion venting in tight sands, the latter because these wells are not included in state data (See Appendix B). For all of these sources which are believed to be under estimated in the U.S. GHG Inventory, there are Natural Gas STAR reductions reported by production partners for year 2006 of 67 Bcf. However, Natural Gas STAR reports generally do not state exactly where the reported reductions were made, and in the case of production, whether they were onshore or offshore or included oil and gas gathering equipment. Therefore, EPA has concluded that the increase in emissions not accounted for in the U.S. GHG Inventory approximately offset the reductions reported by Natural Gas STAR production partners. Because it is not feasible to map the emissions reductions reported by

Natural Gas STAR Partners to their respective facilities, apportioning reductions equally would distort the threshold analysis. Hence, the threshold analysis does not include both the revised estimates from storage tanks (and other missing sources) and reductions from Natural Gas STAR because they cancel out.[26]

- The combustion emissions from the following sources were estimated separately as they are not included in the U.S GHG Inventory: heater-treater, well drilling (oil and gas), dehydrator reboiler, and acid gas removal (AGR) units.
    - **Heater-Treaters Combustion:** The total national combustion emissions from heater-treaters were calculated by estimating the total fuel required to increase the temperature by 10°C of total oil produced in 2006. CO_2 and N_2O combustion emission factor for natural gas from the API compendium 2004 was used to estimate the total national CO_2 and N_2O emissions. The total emissions were apportioned to the operators based on their oil production volumes.
    - **Dehydrator and AGR Combustion:** The total national combustion emissions from dehydrators and AGR units were estimated by applying the fuel consumption factor of 17 Mcf of natural gas/ MMcf of gas throughput, obtained from the EPA's Lesson Learned 2006, *Replacing Glycol Dehydrators with Desiccant Dehydrator*. The total national throughput was assumed to be equal to the total national gas produced obtained from the EIA. CO_2 and N_2O combustion emission factor for natural gas from the API compendium 2004 was used to estimate the total national CO_2 and N_2O emissions. The total emissions were apportioned to the operators based on their gas production volumes.
    - **Well Drilling Combustion:** The total national combustion emissions from well drilling was estimated by multiplying the emissions per well drilled with the national number of oil and gas wells drilled in the year 2006. The emissions per well was estimated by assuming the use of two 1500 hp diesel engines over a period of 90 days to drill each well. CO_2 and N_2O combustion emission factor for diesel from the API compendium 2004 was used to estimate the total national CO_2 and N_2O emissions. The total emissions were apportioned to different states based on the percentage of rigs present in the state. The number of rigs per state was obtained from Baker Hughes. The total oil and gas well drilling combustion emissions per state was apportioned to each operator in the state based on their oil and gas volumes respectively.
- The total barrels of oil produced per field and operator using EOR operations was obtained from the OGJ (2006) *EOR/Heavy Oil Survey*.

[26] A similar issue occurs with the other segments of the industry. For processing facilities, emissions from flares are not included in the threshold analysis. For transmission segment, emissions from scrubber dump valves and compressor unit isolation valves are not included in the threshold analysis. For the distribution segment, the emission from combustion sources are not included in the threshold analysis. The missing and under accounted emissions estimates roughly offset the Natural Gas STAR reductions reported. Hence, EPA has assumed that the missing and under-accounted cancel out the Natural Gas STAR Reductions and therefore did not include them in the threshold analyses.

- The total make-up CO_2 volume required for EOR operations was estimated using 0.29 metric tons CO_2/ bbl oil produced from EOR operations obtained from DOE, *Storing CO_2 with Enhanced Oil Recovery*. The total recycled CO_2 volumes per operator was estimated using a factor of 0.39 metric tons CO_2/bbl estimated from DOE, *Storing CO_2 with Enhanced Oil Recovery.*
- The equipment count for EOR operations was estimated by apportioning the U.S. GHG Inventory activity factors for onshore petroleum production to each field using the producing well count or throughput (bbl) based on judgment. E.g. the total number of compressors in the US used in EOR onshore production operations per field was estimated by using the ratio of the throughput per field to the national throughput and multiplying it by the total number of national compressors in onshore operations.
- The emission factors in the U.S. GHG Inventory and the re-estimated activity factors for EOR operations were used to estimate total methane emissions by volume for EOR operations. This volume was adjusted for methane composition (assumed to be 78.8% from GRI) to estimate the natural gas emissions from EOR operations. The composition of 97% CO_2 and 1.7% CH_4 was applied to the total natural gas emissions to estimate CO_2 and CH_4 emissions from leaking, vented, and combustion sources covered in the U.S. GHG Inventory 97% CO_2 and 1.7% CH_4 composition was obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR) Injection Well Technology.*
- The following EOR emissions sources are not covered in the U.S. GHG Inventory and therefore were estimated separately:
    - Recycled injection CO_2 dehydrator vented emissions
    - Recycled injection CO_2 compressor - vented and combustion emissions
    - CO_2 injection pumps - combustion and vented emissions
    - Water injection pumps – combustion emissions
    - Orifice meter - vented emissions from calibration

Emissions from the above mentioned sources were calculated in the following manner:

- **Recycled CO_2 Dehydrator**: The number of dehydrators per EOR field was estimated by using the ratio of gas throughput to the number of dehydrators indicated in the GRI report and multiplying it by the recycled CO_2 volumes. The recycled dehydrator vented emissions were estimated using readjusted U.S. GHG Inventory emission factor. The GRI methane emission factor was divided by 78.8% methane composition to calculate the natural gas emission factor. The natural gas emission factor was adjusted to EOR operation using the critical density of CO2. 97% CO_2 and 1.7% CH_4 composition obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2EOR) Injection Well Technology* was used to estimate emissions.
- **Recycled CO_2 Injection compressor**: The recycled CO_2 injection compressor fuel gas requirement was estimated using an assumed value of 65 kWhr/metric ton CO2 injected. The assumption was based on the DOE study, *Electricity use of EOR with Carbon dioxide*. It is assumed that only 50% of the injected CO2 requires natural gas powered compressors. CH_4 and CO_2 combustion emissions were estimated by applying API compendium relevant combustion emission factors to the fuel gas used by each operator. The fuel gas consumption was estimated using the horsepower

requirements of engines per operator. N_2O (CO_2e) combustion emissions were estimated by applying API compendium N_2O combustion emission factors to the fuel gas used by each plant. The number of compressor per field was estimated using an assumed number of 12 hp/ bbl of EOR produced oil. This number was obtained from *Enhanced Recovery Scoping Study* conducted by the state of California. It is assumed that a typical compressor used in EOR operations is 3000 hp. This number is obtained from DOE study, *Electricity use of EOR with Carbon dioxide*. The compressor blowdown emissions was estimated assuming one blowdown event per year, the estimated number of compressors per field, and compressor blowdown emission factor obtained from the U.S GHG inventory. The compressor blowdown emission factor was adjusted for critical CO_2 density, CO_2 and CH_4 gas composition. 97% CO_2 and 1.7% CH_4 composition obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology* was used to estimate emissions. .

- **CO2 Injection pumps**: The supercritical CO_2 injection pumps are assumed to be electrically driven and therefore have no combustion emissions. 97% CO_2 and 1.7% CH_4 composition obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2EOR) Injection Well Technology* was used to estimate emissions. The pump blowdown emissions were estimated assuming an internal diameter of 12 inches and length of 30 feet with a 50% void volume. The pipe length between the blowdown valve and unit valve was assumed to be 10 feet with a diameter of 5.38 inches. It is assumed that the pump and pipeline vent gas equivalent to their volume once a year during blowdown operations. The number of supercritical pumps required per field was estimated by assuming that the EOR operations use pumps with 600 hp with a throughput of 40 Mcf/day. These pump specifications were obtained from an unnamed Natural Gas STAR Partner.
- **Water injection pumps**: The injection pump fuel gas requirement was estimated using an assumed value of 6 kWhr/bbl of oil produced. The assumption was based on the DOE study, *Electricity use of EOR with Carbon dioxide*. It is assumed that only 50% of the injection pumps are natural gas powered. CH_4 and CO_2 combustion emissions were estimated by applying API compendium (2004) relevant combustion emission factors to the fuel gas used by each operator. The fuel gas consumption was estimated using the horsepower requirements of engines per operator. N_2O (CO_2e) combustion emissions were estimated by applying API compendium N_2O combustion emission factors to the fuel gas used by each plant.
- **Orifice Meter Vented Emissions**: It is assumed that there are 5 orifice meters for each field based on data provided by an unnamed Natural Gas STAR Partner. The orifice meters are assumed to be calibrated once per year during which the volume of meter is vented to the atmosphere. The orifice meters are assumed to be 8 inches in diameter and 12 feet in length. 97% CO_2 and 1.7% CH_4 composition obtained from *Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology* was used to estimate emissions.
- The total emissions per operator were calculated by summing up all the process and combustion emissions for EOR operations and onshore production.
- Each operator was assigned a "1" if it crossed a threshold and a "0" otherwise, by running the following logic checks:
    - IF(operator total emissions > 1000) then reporting

- IF(operator total emissions > 10000) then reporting
- IF(operator total emissions > 25000) then reporting
- IF(operator total emissions >100000) then reporting

Threshold Analysis for Offshore Production

- Federal GOM offshore platforms, by their complex ID, and their corresponding CO_2 combustion and equipment leak emissions (CO_2e), CH_4 equipment leaks (CO_2e), CH_4 vented emissions (CO_2e), and N_2O combusted emissions (CO_2e) for the year 2000 was obtained from the BOEMRE Goads Summary Access File "Final GOADS Emissions Summaries"
- The ratio of 2006 to 2000 Gulf of Mexico offshore productions was calculated and applied to the emissions from each platform to estimate emissions for the year 2006.
- The total number of GOM offshore production platforms was obtained from the BOEMRE website.
- Each platform was assigned a "1" or "0" based on if it crossed an emissions threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- The total number of state platforms (Alaska and Pacific) was obtained from the Alaska Division of Oil and Gas and *Emery et al*[27] respectively. The number of state and federal offshore oil and gas wells for GOM, Pacific, and Alaska was obtained from the LASSER™ database. The ratio of federal GOM oil and gas wells to federal platforms and the number of state offshore oil and gas wells were used to estimate the state GOM platform count.
- The ratio of gas to oil platforms was obtained from the U.S GHG Inventory 2006. All the state offshore platforms were assumed to be shallow water platforms.
- The state offshore equipment leak, vented, and combustion emissions were estimated by applying the ratio of state to federal platforms and multiplying it by the federal offshore equipment leak, vented, and combustion emissions.
- The percentage of platforms that fall within each emissions threshold (1000, 10,000, 25,000 and 100,000 metric tons CO_2e) for the federal GOM offshore was calculated and applied to the estimated state equipment leak, vented, and combustion emissions to calculate the volume of state offshore emissions that fall within each threshold.
- The number of state platforms that fall within each category was estimated by taking the ratio of federal emissions to platform count within each threshold and multiplying it by the state emissions covered by each threshold.
- The emissions from state and federal offshore platforms were summed up to estimate the total emissions from offshore operations

[27] Emery, Brian M. et al. *Do oil and gas platforms off California reduce recruitment of bocaccio (Sebastes paucispinis) to natural habitat? An analysis based on trajectories derived from high frequency radar*. http://www.icess.ucsb.edu/iog/pubs/DrifterSimulationsFinal_v5.pdf

Threshold Analysis for Processing

- US gas processing plants, plant throughputs, and equipment count per plant were obtained from the OGJ (2006). 2005 and 2006 emissions are assumed to be the same on a plant basis as the total national throughput from 2005 to 2006 did not change significantly and were 45,685 MMcf/d and 45,537.4 MMcf/d respectively as indicated by the U.S. GHG Inventory
- CH_4 and CO_2 process emissions (CO_2e) per facility were estimated by multiplying the equipment count per plant (activity factor) obtained from the Gas Processing Survey with their corresponding emission factors obtained from GRI/ EPA 1996 reports. The national processing sector average composition (CH_4 and CO_2 content) of natural gas was obtained from GTI and applied to the GRI emission factors. Emission factor for centrifugal compressor wet seals was obtained from Bylin et al[5]. Due to the uncertainty in centrifugal compressor wet seal emissions, the point that it is not possible to ascribe Natural Gas STAR processing partner emission reductions to a particular processing plant or even to processing plants in general as opposed to gas gathering equipment, the Natural Gas STAR reported processing reductions of 6 Bcf/year were not incorporated into this analysis[26].
- CH_4, CO_2 and N_2O combustion emissions (CO_2e) were estimated by applying CH_4, CO_2 and N_2O API compendium relevant combustion emission factors to the fuel gas used by each plant. The fuel gas consumption was estimated using the horsepower requirements of engines and turbines per plant.
- N_2O combustion emissions (CO_2e) were estimated by applying API compendium N_2O combustion emission factors to the fuel gas used by each plant.
- The different emissions per plant was summed up to provide total emissions (CO_2e)
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
    - IF(operator total emissions > 1000) then reporting
    - IF(operator total emissions > 10000) then reporting
    - IF(operator total emissions > 25000) then reporting
    - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered at each threshold.
- The resulting O&M and capital costs from the cost burden analyses were entered for each facility in the spreadsheet. The sum of the product of O&M or capital costs and the logic checks described above provides the total cost burdens for each reporting threshold. Dividing the total cost burdens by the number of reporting facilities (calculated above) provides the average facility cost burdens at each reporting threshold.

Threshold Analysis for Transmission

- "Facility" in the natural gas transmission segment is defined as a compressor station. Data for individual compressor stations on interstate transmission pipelines are

reported to FERC Form 2[28], and data for compressor stations on intrastate pipelines were obtained from EIA through personal contact. However, the data collected for intrastate pipelines were incomplete.

- For intrastate pipeline facilities that did not have the number of compressor stations listed, it was assumed that each facility has one compressor. The compressor horsepower per intrastate pipeline was estimated by multiplying design throughput per intrastate pipeline with the ratio of total interstate pipeline compressor horsepower (engine and turbine) to the total interstate design throughput.
- The FERC data, supplemented with intrastate data and assumptions, list pipeline states, names, designed throughput capacity, and in some cases the type of compressor (centrifugal, reciprocating, and/or electric), and the installed horsepower for each station.
- In cases where the installed reciprocating horsepower is provided, it was used for installed engine capacity (Hp). In cases where the installed capacity was provided, but the type of compressor was not specified, the analysis assumes that 81% of the installed capacity is reciprocating. In cases where the provided installed capacity is both centrifugal and reciprocating, it is assumed that 81% is for engines. The 81% assumption is the ratio of reciprocating compressor engine capacity in the transmission sector to centrifugal turbine drivers for 2006 taken from the U.S. GHG Inventory
- The ratio of reciprocating compressor engine driver energy use (MMHphr, EPA[1]) to interstate station design throughput capacity (MMcfd, FERC[28]) was calculated. Then, the reciprocating compressor energy use for each station was assigned by multiplying the installed station throughput capacity by the ratio calculated previously in this bullet.
- In cases where the installed centrifugal horsepower is provided, it was used directly for installed turbine capacity (Hp). In cases where the installed capacity was provided, but the type of compressor was not specified, the analysis assumes that 19% of the installed capacity is centrifugal. In cases where the provided installed capacity is both centrifugal and reciprocating, it is assumed that 19% is for turbines. The 19% assumption is the ratio of centrifugal compressor turbine capacity in the transmission sector to reciprocating engine drivers taken from the U.S. GHG Inventory.
- The ratio of centrifugal compressor engine driver energy use (MMHphr, EPA[1]) to interstate station design throughput capacity (MMcfd, FERC[28]) was calculated. Then, the reciprocating compressor energy use for each station was assigned by multiplying the installed station throughput capacity by the ratio calculated previously in this bullet.
- The total emissions for 2006, both vented and equipment leak methane and non-energy CO_2, were estimated in the U.S. GHG Inventory. Emission factor for centrifugal compressor wet seals was obtained from Bylin et al[5]. Due to the uncertainty in centrifugal compressor wet seal emissions, the point that it is not possible to ascribe Natural Gas STAR transmission partner emission reductions to a

[28] FERC. *Form 2 Major and Non-major Natural Gas Pipeline Annual Report.* Available online at: <http://www.ferc.gov/docs-filing/eforms/form-2/data.asp#skipnavsub>.

particular compressor station or even to transmission in general as opposed to gas storage equipment, the Natural Gas STAR reported transmission reductions of 25 Bcf/year were not incorporated into this analysis[26]. The total emissions were allocated to each facility based on its portion of the segment's total station throughput capacity, as shown in the following equation:

$$\text{Station "}i\text{" process emissions} = \frac{StationCapacity_i}{\sum_i StationCapacity} \times TotalInventoryEmissions$$

- Combustion CO_2 and N_2O emissions were estimated for each facility by applying the following emission factors:
  - EF_{CO2} = 719 metric tons CO_2e/MMHphr
  - EF_{N20} = 5.81 metric tons CO_2e/MMHphr
  - $Emissions_{CO2\ or\ N20} = EF_{CO2\ or\ N20} \times \text{Compressor energy}_i$ (MMHphr)
- The total emissions for each facility were calculated by summing the calculated process and the combustion emissions.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered at each threshold.

Threshold Analysis for Underground Storage

- "Facility" in the underground natural gas storage segment is defined as storage stations and the connected storage wellheads. Underground storage data by operator are collected in form EIA-176[29].
- The data collected in EIA-176 contained each underground storage operator, field, and location as well as the storage capacity and maximum daily delivery.
- The total compressor energy use in 2006 for the underground storage segment was estimated in the U.S. GHG Inventory. This total energy use, in millions of horsepower hours (MMHphr), is allocated to each facility based on its portion of the segment's total maximum daily delivery capacity; as described in the following equation:

[29] EIA. *EIA-176 Query System*. Available online at: <http://www.eia.doe.gov/oil_gas/natural_gas/applications/eia176query_historical.html>.

$$\text{Compressor energy}_i\ (\text{MMHphr}) = \frac{MaximumDailyDelivery_i}{\sum_i MaximumDailyDelivery} \times TotalSegmentMMHphr$$

Where, index "*i*" denotes an individual facility

- The total process emissions for 2006, both vented and equipment leak methane and non-energy CO_2, were estimated in the U.S. GHG Inventory. These total process emissions were allocated to each facility based on its portion of the segment's total maximum daily delivery capacity, using the same methods as compressor energy use.
- Combustion CO_2 and N_2O emissions were estimated for each facility by applying the following emission factors:

  EF_{CO2} = 719 metric tons CO_2e/MMHphr

  EF_{N20} = 5.81 metric tons CO_2e/MMHphr

  $\text{Emissions}_{CO2\ or\ N20} = EF_{CO2\ or\ N20} \times \text{Compressor energy}_i\ (\text{MMHphr})$
- The total emissions for each facility were calculated by summing the calculated process and the combustion emissions.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered at each threshold.

Threshold Analysis for LNG Storage

- "Facility" in LNG storage segment is defined as LNG storage plants (peak shaving or satellite). Data for each peak shaving facility is provided in *The World LNG Source Book – An Encyclopedia of the World LNG Industry*. Summary data for all satellite facilities is estimated in the *Additional Changes to Activity Factors for Portions of the Gas Industry* background memo for EPA's U.S. GHG Inventory.
- The data reported in *The World LNG Source Book – An Encyclopedia of the World LNG Industry* includes the operator, liquefaction capacity, storage capacity, vaporization design capacity for each individual peak shaving plant.
- U.S GHG Inventory reports that in addition to peak shaving plants there are approximately 100 satellite facilities with a total storage capacity of 8.7 Bcf. The ICF memo also provides several key assumptions that will be discussed at the appropriate locations below.
- The total liquefaction compressor energy use for the segment was estimated using the methods and assumptions detailed in the background memo for EPA's U.S. GHG Inventory. LNG company contacts provided the memo's assumption that 750 MMHphr are required for liquefaction for each million cubic feet per day of liquefaction capacity. It assumes the liquefaction takes place over a 200-day "fill"

season. It assumes that approximately 50% of compressors are driven by gas-fired engines or turbines. EIA provides the LNG storage additions for 2006 on its website, totaling 38,706 MMcf. Thus, the total liquefaction energy use for the segment was calculated using the following formula:

$$\text{LEU} = \frac{38{,}706 MMcf}{200 days} \times \frac{750 Hp}{1 MMcfd} \times \frac{24 hours}{day} \times 200 days \times 50\% \times \frac{1 MMHphr}{1{,}000{,}000 Hphr}$$

where,

LEU = total liquefaction energy use for the segment, gas fired (MMHphr)

- The total calculated liquefaction compressor energy use was apportioned to individual facilities based on their share of the total liquefaction capacity for the segment, as shown in the following equation:

$$\text{Facility "i" liquefaction MMHphr} = \frac{LC_i}{\sum_i LC} \times TotalSegmentMMHphr$$

Where "i" indexes facilities and LC = liquefaction capacity.

- Storage capacity, provided in gallons by *The World LNG Source Book – An Encyclopedia of the World LNG Industry*, was converted to million cubic feet with a conversion factor of 1 gallon of LNG = 81.5 standard cubic feet of natural gas.
- Boil-off liquefaction compressor energy use was calculated using assumptions outlined in the U.S GHG Inventory. The memo assumes that 0.05% of storage capacity boils off and is recovered by vapor recovery compressors and liquefied. These compressors must operate all year and require the same 750 Hp per 1 MMcfd liquefied. The boil-off liquefaction compressor energy use was thus estimated for each facility using the following equation:

$$\text{FBEU}_i = \frac{SC_i \times 0.05\%}{365 days} \times \frac{750 Hp}{MMcfd} \times \left[365 days \times \frac{24 hours}{day} \right] \times \frac{MMHphr}{1{,}000{,}000 Hphr}$$

where,

FBEU_i = Facility "i" boil-off liquefaction compressor energy use (MMHphr)

SC = Facility "i" storage capacity (MMcf)

- Vaporization and send-out compressor energy use was also calculated based on assumptions from the U.S GHG Inventory. It estimates that with an average send-out pressure of 300 psia and inlet pressure of 15 psia, using 2-stage compression, a satellite facility requires 1.86 MMHphr for each MMcfd of send-out. The send-out period lasts all year, unlike the "fill" season. The memo also estimates that 75 Bcf of gas were sent out from peak shaving facilities compared to 8.7 Bcf from satellite facilities in 2003. This equates to 89.6% of send-out coming from peak shaving plants in 2003; the analysis assumes the same is true for 2006. EIA[30] provides that in 2006, total LNG withdrawals were 33,743 MMcf. The send-out compressor energy

[30] EIA. *Liquefied Natural Gas Additions to and Withdrawals from Storage*. Available online at: <http://tonto.eia.doe.gov/dnav/ng/ng_stor_lng_dcu_nus_a.htm>.

use by all peak shaving plants in the segment was calculated using the following equation:

$$\text{Total send-out energy use} = \frac{33{,}743 MMcf}{365 days} \times \frac{1.86 MMHphr}{MMcfd} \times 89\ 6\%$$

- Send-out compressor energy use was apportioned to each peak shaving facility by its share of the total peak shaving segment's send-out capacity; using the same method as apportioning liquefaction energy use. (See liquefaction bullet).
- The 100 satellite facilities were assumed to be equal size and capacity. That is, 8.7 Bcf storage capacity, all of which is sent out each year. It was assumed that satellite facilities have no liquefaction, except for that which is necessary for boil-off. We performed the above analysis on the "average" satellite facility to estimate its energy use and emissions. The only difference was that 10.4% of EIA reported LNG withdrawals was attributed to the satellite facilities.
- The total process emissions for 2006, both vented and equipment leak methane and non-energy CO_2, were estimated in the U.S. GHG Inventory. These total emissions were allocated to each facility based on its portion of the segment's total storage capacity, using the same methods as apportioning liquefaction and send-out compressor energy use.
- Combustion CO_2 and N_2O emissions were estimated for each facility by applying the following emission factors:

  EF_{CO2} = 719 metric tons CO_2e/MMHphr

  EF_{N20} = 5.81 metric tons CO_2e/MMHphr

  $Emissions_{CO2\ or\ N20} = EF_{CO2\ or\ N20} \times \text{Compressor energy}_i$ (MMHphr)
- The total emissions for each facility were calculated by summing the calculated equipment leak, vented, and combustion emissions.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered by each threshold.
- Satellite facilities crossed the 1,000 and 10,000-metric ton reporting threshold, but fell well short of the 25,000-metric ton threshold.

Threshold Analysis for LNG Import Terminals

- "Facility" in the LNG import segment is defined as the import terminals. Data is available for this on the FERC website[31]. It provides the owner, location, capacity, and 2006 import volumes for each LNG terminal.
- ICF *Additional Changes to Activity Factors for Portions of the Gas Industry* background memo for EPA's U.S. Inventory assumptions were used to estimate liquefaction, boil-off liquefaction, and send-out compressor energy use for each of the LNG import terminals.
- It was assumed that import terminals do not have liquefaction capacity.
- Boil-off liquefaction compressor energy use was calculated using assumptions outlined in ICF *Additional Changes to Activity Factors for Portions of the Gas Industry* background memo for EPA's U.S. Inventory. The memo assumes that 0.05% of capacity boils off and is recovered by vapor recovery compressors and liquefied. These compressors must operate all year and require the same 750 Hp per 1 MMcfd liquefied. The boil-off liquefaction compressor energy use was thus estimated for each facility using the following equation:

$$FBEU_i = \frac{IV_i \times 0.05\%}{365 days} \times \frac{750 Hp}{MMcfd} \times 365 days \times \frac{24 hours}{day} \times \frac{MMHphr}{1{,}000{,}000 Hphr}$$

where,

$FBEU_i$ = Facility "i" boil-off liquefaction compressor energy use (MMHphr)

IV_i = Facility "i" import volume (MMcf)

- Vaporization and send-out compressor energy use was also calculated based on assumptions from ICF *Additional Changes to Activity Factors for Portions of the Gas Industry* background memo for EPA's U.S. GHG Inventory. It estimates that with an average send-out pressure of 300 psia and inlet pressure of 15 psia, using 2-stage compression, satellite facilities require 1.86 MMHphr for each MMcfd of send-out. The following equation estimates the energy use at each facility:

$$\text{Facility "i" send-out energy use} = \frac{IV_i}{365 days} \times \frac{1.86 MMHphr}{MMcfd}$$

- The total process emissions for 2006, both vented and equipment leak methane and non-energy CO_2, were estimated in the U.S. GHG Inventory. These total process emissions were allocated to each facility based on its portion of the segment's total import volume, using the following equation:

$$\text{Facility "i" process emissions} = \frac{IV_i}{\sum_i IV} \times InventorySegmentEmissions$$

where,

IV_i = import volume and "i" represents individual facilities

- Combustion CO_2 and N_2O emissions were estimated for each facility by applying the following emission factors:

EF_{CO2} = 719 metric tons CO_2e/MMHphr

[31] FERC. *Import Terminals*. Available online at: <http://www.ferc.gov/industries/lng.asp>.

EF_{N20} = 5.81 metric tons CO_2e/MMHphr
$Emissions_{CO2\ or\ N20} = EF_{CO2\ or\ N20} \times$ Compressor $energy_i$ (MMHphr)

- The total emissions for each facility were calculated by summing the calculated process and the combustion emissions.
- Since there were only 5 active import terminals, all were assumed to be "medium" in size.
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered by each threshold.

Threshold Analysis for Distribution

- "Facility" in the natural gas distribution segment is defined as the local distribution company (LDC). The Department of Transportation (DOT)[32] provides a set of data that contains distribution main pipelines miles by pipeline materials and distribution service counts by pipeline material for each LDC.
- CO_2 and CH_4 equipment leaks from distribution mains were evaluated for each facility by multiplying its pipeline data by the appropriate emission factor, summarized in the table below, from the U.S GHG Inventory[1].

Exhibit C-8: LDC's Equipment Leak Emission Factors

Pipeline Type/Material	Equipment Leak Emission Factor
Mains – Unprotected Steel	110 Mcf/mile/year
Mains – Protected Steel	3.07 Mcf/mile/year
Mains – Plastic	9.91 Mcf/mile/year
Mains – Cast Iron	239 Mcf/mile/year
Services – Unprotected Steel	1.70 Mcf/service/year
Services – Protected Steel	0.18 Mcf/service/year
Services – Plastic	0.01 Mcf/service/year
Services – Copper	0.25 Mcf/service/year

- The total miles of mains pipelines of all materials were summed for each LDC.
- The total emissions from metering and regulating (M&R) stations for 2006, both vented and equipment leak methane and non-energy CO_2, were estimated by EPA

[32] DOT. *2006 Distribution Annuals Data*. Available online at: <http://www.phmsa.dot.gov/pipeline/library/data-stats>.

U.S GHG Inventory. These total emissions were allocated to each facility based on its portion of the segment's total import volume, using the following equation:

$$\text{Facility "i" M\&R emissions} = \frac{MM_i}{\sum_i MM} \times InventorySegmentEmissions$$

where,

MM = total miles of mains pipeline, and "i" represents individual facilities

- The total emissions for each facility were calculated by summing the calculated pipeline leaks and M&R station emissions[26].
- Each facility was assigned a "1" or "0" based on if it crossed a threshold by running the following logic checks:
  - IF(operator total emissions > 1000) then reporting
  - IF(operator total emissions > 10000) then reporting
  - IF(operator total emissions > 25000) then reporting
  - IF(operator total emissions >100000) then reporting
- Summing the results of the above logic checks for each threshold provided the number of facilities exceeding that threshold.
- Multiplying the logic checks above by the total emissions for each facility, then summing the results yielded the total emissions covered at each threshold.

Appendix D: Analysis of potential facility definitions for onshore petroleum and natural gas production

The purpose of this appendix is to determine the barriers in using a physical definition of a facility for the onshore petroleum and natural gas production segment. The paper also discusses a potential alternative to a physical definition by using a corporate level reporter definition.

A. **Facility Definition:** Any production sector reporting configuration will need specific definitions on what constitutes a facility.

i. Field level – A field may be defined by either physically aggregating certain surface equipment, referred to as physical field definition. Or the field may be defined by demarcation of geographical boundaries, referred to as Geographic field definition.

Physical field definition:
The challenge in defining a field as a facility is to recognize a common structure through the oil and gas production operations. Such a definition can be achieved by identifying a point in the system upstream of which all equipment can be collectively referred to as a field level facility. All oil and gas production operators are required by law to meter their oil and gas production for paying royalties to the owner of the gas and taxes to the state, referred to as the lease meter. All equipment upstream of this meter can be collectively referred to as a facility.

There is no precedence for such a definition in the CAA. It must be noted, however, that the facility definitions commonly used in the CAA pertain specifically to pollutants whose concentration in the ambient atmosphere is the deciding factor on its impact. This is not necessarily true of GHGs that have the same overall impact on climate forcing irrespective of how and where they occur.

Geographic field definition:
An alternative to the lease meter field level definition is to use the EIA Oil and Gas Field Code Master[33] to identify each geological field as a facility. This definition is structurally similar to the corporate basin level definition, i.e. it uses geological demarcations to identify a facility rather than the above ground operational demarcation.

ii. Basin level – The American Association of Petroleum Geologists (AAPG) provides a geologic definition of hydrocarbon production basins which are referenced to County boundaries. The United States Geological Survey (USGS) also provides such a definition, which is different than the AAPG definition. The

[33] EIA Oil and Gas Field Master – 2007, http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/field_code_master_list/current/pdf/fcml_all.pdf

AAPG definition identified by the "geologic province code" is most commonly used by the industry and can be used to report emissions from each basin. The individual counties in each state are allocated to different geologic province codes and therefore there is no ambiguity in associating an operation with the relevant basin (geologic province code). An operation physically located on a basin as defined by the AAPG can be identified with that particular basin, irrespective of which basins the wells are producing from. (Well pads may have multiple wells producing from different fields and zones in a reservoir, and possibly different basins as well).

B. Level of Reporting: It is important to clearly distinguish the level of reporting- i.e., the facility level or the corporate level. The level of reporting is where the threshold level is applied and thus determination on whether reporting is required. In some cases, the owner or operator of the facility itself is the reporter and in other cases it is the overall company that is the reporter. For example, in subpart NN of the MRR published on September 22, 2009, reporting for natural gas sent to the end use customers is at the local distribution company, and not the individual physical locations (or facilities) that send the natural gas into the economy. Alternatively, in subpart MM of the initial rule proposal, the owner or operator of the individual refinery is the reporter as opposed to the company owning multiple refineries.

For the purposes of onshore petroleum and natural gas production reporting can be at either the facility level or the corporate level. If the level of reporting is at the corporate level, it could still be required that data be reported for individual facilities.

C. Qualitative Analysis of Facility Options

The following qualitative evaluation provides a discussion on the advantages and disadvantages of using any of the three reporting level definitions, based on expert opinion.

i. Ease of practical application of reporter and facility definitions

1) Field level facility definition – In this case the physical demarcation of field level by aggregating field equipment is difficult to implement. On the other hand, field level definition based on boundaries identified by the EIA Oil and Gas Field Code Master should be easy to implement, since the classification if widely used in the industry.

Physical Field Definition:
There are no standard guidelines or operational practices on how many wells can be connected to one lease meter. The choice of whether multiple wells are connected to the same lease meter depends on; the well spacing, number of owners of leases, volume of hydrocarbons produced per well, geographical boundaries, and ease of operation. Therefore, such a definition will lead to

facilities of all kinds of sizes; at one extreme several well pads with multiple wells could be connected to one lease meter, while at the other extreme where situation demands only one well with no equipment could directly be connected to a lease meter. In addition there will be thousands of facilities that will be under purview.

Any lease meters located upstr eam of a compression system will exclude compressors from the facility definition. This means that the required threshold for emissions reporting may not be reached due to exclusion of the equipment leaks as well as the combustion emissions from compressors. Alternatively, the threshold will have to be set very low to capture any reasonable amount of emissions from field level definition.

Geographic field definition:
The EIA publishes its Field Code Master on a yearly basis. Also, the classification system is widely used in the industry. Hence such a definition should be easy to implement.

2) Basin level facility definition - Basin level definition is more practical to implement given that operational boundaries and basin demarcations are clearly defined. Furthermore, more emissions will be captured under this facility definition than the field level or well level definitions.

3) Corporate reporting -
It can be difficult to identify who the corporation is that would be responsible for reporting. If the corporation can be readily identified and defined then applying a field level facility definition using the EIA field classification or basin level facility definition using AAPG classification becomes practical.

ii. Coverage that can be expected from each definition type

1) Field level facility definition – This definition (both physical and geographical) provides the highest level of detail possible on emissions sources. However, any field level definition along with a 25,000 metric tons CO_2e/year threshold for reporting could potentially exclude a large portion of the U.S. oil and gas operations. Hence only a portion of the entire emissions from the U.S. oil and gas operations will get reported.

2) Basin level facility definition - Basin level information will throw light on the difference in patterns of emissions from sources both as a result of being located in different basins and as a result of different operational practices in different companies. This definition will result in the reporting of a significant portion of the emissions for the identified sources from the entire U.S. onshore oil and gas operations.

3) Corporate reporting - This definition will result in reporting of a significant portion of the emissions for the identified sources from the entire US onshore oil and gas operations. Since the reporting will be at a company level, variations in emissions from sources due to location on different basins may not be evident. However, if corporate national level reporter definition is used in addition to field and/or basin level reporting then all possible patterns in emissions will be evident.

D. Data Sources for Research and Analysis

i. Clean Air Act
ii. United States Geological Survey
iii. Natural Gas STAR Technical Documents
iv. EPA National GHG Inventory
v. DOE GASIS database
vi. Lasser® database
vii. Energy Information Administration
viii. Oil & Gas Journal
ix. HARC - VOC Emissions from Oil and Condensate Storage Tanks
x. State Oil and Gas Commissions
xi. American Association of Petroleum Geologists

Appendix E: Development of multipliers to scale emissions or miscellaneous sources connected to storage tanks

This method of quantifying tank emissions assumes that thermodynamically based models such as E&P Tank can accurately predict the effect of flashing emissions from hydrocarbons in fixed roof storage; but are unable to predict or account for emissions from vortexing or dump valves. Either direct measurement or a correction factor is required to represent the total emissions from hydrocarbon storage tanks.

This appendix compares two methods of correcting E&P Tank (GEO-RVP) data to account for non-flashing emission effects on tanks. Actual measurement data from a Texas Commission on Environmental Quality (TCEQ) report[34] were compared to E&P Tank (GEO-RVP) data runs on the same tanks to develop a correction factor which can be applied to E&P Tank (GEO-RVP) results in which additional non-flashing emissions or vortexing are detected.

Selected Data

All data considered were presented in a TCEQ-funded report that compared tank emission predicting equations, charts, and models to actual measured data. Data from the E&P Tank 2.0 GEO-RVP setting were compared against to direct measurement results. The TCEQ study focused on comparing the various methods of predicting VOC portion of emissions; however, for the purposes of this analysis, the total gas-oil ratios were compared.

Where direct measurement results were within ±100% of E&P Tank (GEO-RVP) results, those tanks were assumed to be exhibiting typical flashing emissions only. Direct measurement results greater or less than ±100% of E&P Tank (GEO-RVP) results were used to develop a correction factor for non-flashing effects on tank emissions.

The data were separated into two regimes:

- Hydrocarbon liquids with API gravities less than 45˚API were considered "oil"
- Hydrocarbon liquids with API gravities greater than 45˚API were considered "condensate"

Correction factors were developed for both ranges.

Method 1 – Least Squares Analysis of Emission Difference

The first method sorts qualifying tanks in ascending order of emission rates estimated by the E&P Tank (GEO-RVP) runs. The difference between the measured emission rate and E&P Tank (GEO-RVP) emission rates was plotted against the E&P Tank (GEO-RVP) emission rates and a trend line was fitted to the equation, as shown in Exhibits E-9 and E-10.

Exhibit E-9. Oil Tank Correction Factors

[34] Texas Commission on Environmental Quality (TCEQ). *Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation*. July 16, 2009.

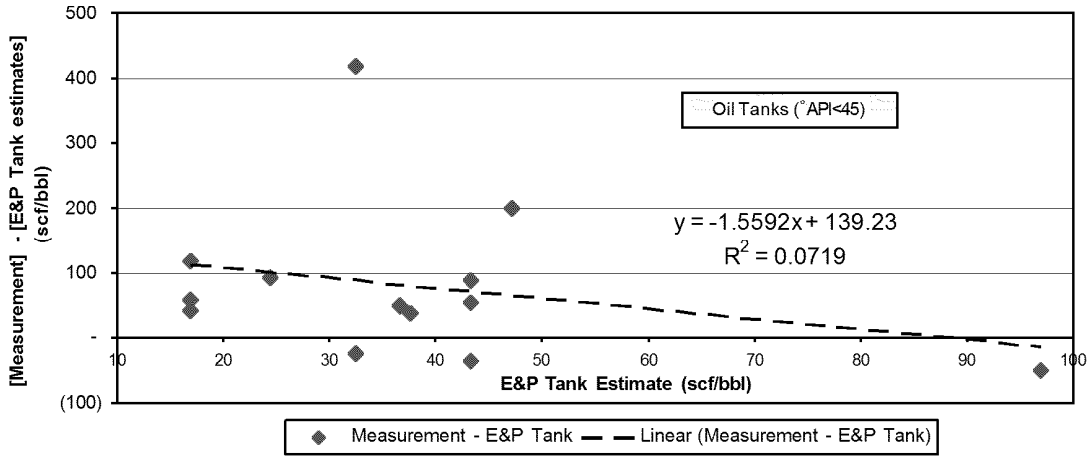
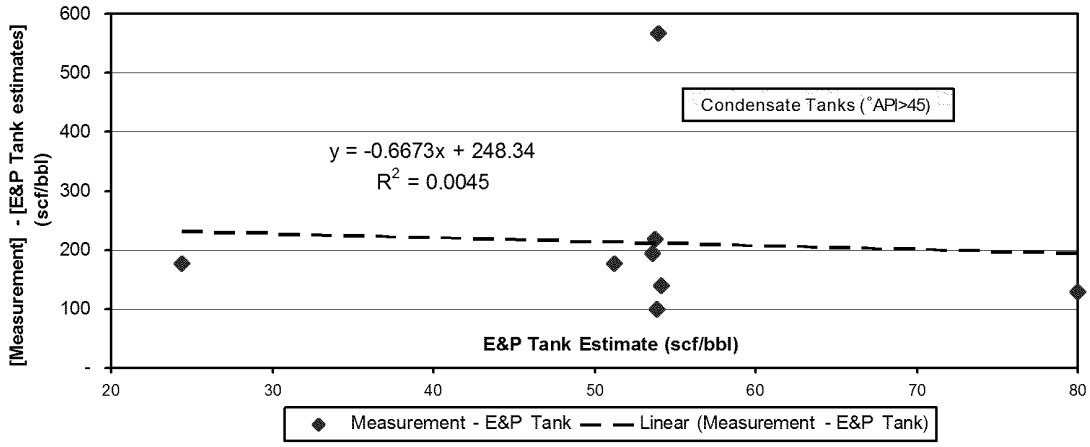


Exhibit E-10. Condensate Tank Correction Factors



The equation for the line of best fit can be used on E&P Tank (GEO-RVP) results where non-flashing emission affects are detected to estimate the true tank emissions. The data used to derive this relationship range from oil gravities from 29.1 to 44.8˚API and separator pressures from 15 to 70 psig; and for condensate gravities from 45.3 to 82.2˚API and separator pressures from 30 to 231 psig.

The E&P Tank (GEO-RVP) emission estimates can be corrected with the following equations:

- For oil: $CE = (-0.5592 \times EE) + 139.23$
- For condensate: $CE = (0.3327 \times EE) + 248.34$

Where "EE" is the E&P Tank (GEO-RVP) emission estimate and "CE" is the corrected emission estimate.

As demonstrated in Exhibits E-9 and E-10, the correlations for the correction factor are very weak, with R^2 values of 0.0719 for oil and 0.0045 for condensate.

Method 2 – Average Emissions Ratio Analysis
This method takes the simple average of the ratio of qualifying measured emission rates to simulated emission rates generated by E&P Tank (GEO-RVP) for the oil and condensate ranges.

Using this method, E&P Tank (GEO-RVP) emission estimates can be corrected with the following equations:

- For oil: $CE = 3.87 \times EE$
- For condensate: $CE = 5.37 \times EE$

Where "EE" is the E&P Tank (GEO-RVP) emission estimate and "CE" is the corrected emission estimate.

Summary
Predicting and evaluating non-flashing effects on emissions (such as dump valves or vortexing) has not yet been thoroughly studied or quantified. The methods above have significant weaknesses as:

1. The sample data set is limited
2. Only weak correlations were observed for the available data.

Method 1 naturally suggests that very low estimates are underestimating the tank emissions and very high estimates (over 89 scf/bbl for oil) are overestimating the emissions. This will tend to "even out" estimates so that none are extremely high or extremely low. It also suggests that if E&P Tank (GEO-RVP) estimates 0 scf/bbl flashing emissions, the emission rates are actually higher than if E&P Tank (GEO-RVP) estimates large (near 89 scf/bbl for oil) emission rates.

Method 2 does not "even out" emission rates, and assumes that in all cases where non-flashing effects are present, each case is uniformly underestimated.

Appendix F: Development of leaker emission Factors

Natural Gas Emission Factors for Onshore Production

Leaker Emission Factors – All Components, Light Crude Service

Methodology
Average emission factors by facility type are taken from API's *Emission Factors for Oil and Gas Production Operations*[35]. Hydrocarbon liquids greater than or equal to 20°API are considered "light crude." The methane content of associated natural gas with onshore light crude is 61.3% is taken from the same API publication, Table ES-4, page ES-3.

Component EF, scf/hour/component = ((Component EF, lb/day THC) * (**A**)) / ((**B**) * (**C**))

Component Name	Component EF, scf/hour/comp	Component EF, lb/day THC
Valve	2.03	3.381
Connector	0.90	1.497
Open-Ended Line	0.96	1.6
Pump	2.35	3.905
Other	2.31	3.846

EF: Emission Factor
THC: Total Hydrocarbons

Conversions:
A: 0.613 – CH_4 content of onshore light crude associated natural gas
B: 0.04246 CH_4 density lb/scf
C: 24 hours/day

Leaker Emission Factors – All Components, Heavy Crude Service

Methodology
Average emission factors by facility type are taken from API's *Emission Factors for Oil and Gas Production Operations*[35]. Hydrocarbon liquids less than 20°API are considered "heavy crude." The methane content of associated natural gas with onshore heavy crude is 94.2% taken from the same API publication, Table ES-4, page ES-3.

Component EF, scf/hour/component = ((Component EF, lb/day THC) * (**D**)) / ((**B**) * (**C**))

Component Name	Component EF, scf/hour/component	Component EF, lb/day THC
Valve	3.13	3.381
Flange	4.15	4.49
Connector (other)	1.38	1.497
Open-Ended Line	1.48	1.6
Other	3.56	3.846

[35] API. *Emission Factors for Oil and Gas Production Operations*. Table 10, page 16. API Publication Number 4615. January 1995.

EF: Emission Factor
THC: Total Hydrocarbons

Conversions:
B: 0.04246 CH_4 density lb/scf
C: 24 hours/day
D: 0.942 – CH_4 content of onshore heavy crude associated natural gas

Total Hydrocarbon Emission Factors for Processing

Leaker Emissions Factors – Reciprocating Compressor Components, Centrifugal Compressor Components, and Other Components, Gas Service

Methodology
The leaker emissions factors are from Clearstone Engineering's *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*[36] and Clearstone's *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*[37]. The components were categorized into three groups: reciprocating compressor related, centrifugal compressor related and all other components. Furthermore, the components related to reciprocating and centrifugal compressor were segregated into components before and after the de-methanizer. Once categorized, the sum of the leak rates from components known to be leaking was divided by the sum of number of leaking components.

Component EF, scf/hour/component = (Leak rate, Mscf/day/component) * (**E**) / (**C**)

Component Name	Reciprocating Compressor Component, (scf/hour/comp)		Centrifugal Compressor Component, (scf/hour/comp)		Other Components, (scf/hour/comp)
	Before De-Methanizer	After De-Methanizer	Before De-Methanizer	After De-Methanizer	
Valve	15.88	18.09	0.67	2.51	6.42
Connector	4.31	9.10	2.33	3.14	5.71
Open-Ended Line	17.90	10.29	17.90	16.17	11.27
Pressure Relief Valve	2.01	30.46	-	-	2.01
Meter	0.02	48.29	-	-	2.93

Conversions:
C: 24 hours / day
E: 1000 scf / Mscf

[36] EPA. *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*. Clearstone Engineering Ltd. June 20, 2002. <www.epa.gov/gasstar/documents/four_plants.pdf>
[37] National Gas Machinery Laboratory, Kansas State University; Clearstone Engineering, Ltd; Innovative Environmental Solutions, Inc. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. For EPA Natural Gas STAR Program. March 2006.

Total Hydrocarbon Emission Factors for Transmission

Leaker Emission Factors – All Components, Gas Service

Methodology
Gas transmission facility emissions are drawn from the *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*[38] and the *Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry*[39]. All compressor related components were separated from the raw data and categorized into the component types. Once categorized, the sum of the leak rates from components known to be leaking was divided by the sum of number of leaking components.

Component EF, scf/hour/component = (Gas Transmission Facility Emissions, kg/h/src) * (**F**) / (**B**)

Component Name	Component EF, (scf/hour/comp)
Connector	2.7
Block Valve	10.4
Control Valve	3.4
Compressor Blowdown Valve	543.5
Pressure Relief Valve	37.2
Orifice Meter	14.3
Other Meter	0.1
Regulator	9.8
Open-Ended Line	21.5

Conversions:
B: 0.04246 CH_4 density lb/scf
F: 2.20462262 lb/kg

Methane Emission Factors for LNG Storage

Leaker Emission Factors – LNG Storage Components, LNG Service

Methodology

[38] Clearstone. *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*. Clearstone Engineering Ltd., Enerco Engineering Ltd, and Radian International. May 25, 1998.
[39] Clearstone. *Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry*. Clearstone Engineering Ltd., Canadian Energy Partnership for Environmental Innovation (CEPEI). April 16, 2007.

The light liquid emission factors with leak concentrations greater than or equal to 10,000 ppmv were taken from *Protocol for Equipment Leak Emission Estimates*[40]. The emissions are assumed to be 100% methane.

Component EF, scf/hour/component = (Light Liquid >= 10,000 ppmv Emission Factor) * (**F**) / (**B**)

Component Name	Component EF, scf/hour/comp	†Light Liquid EF, kg/hr THC
Valve	1.19	2.30E-02
Pump Seal	4.00	7.70E-02
Connector	0.34	6.50E-03
Other	1.77	3.40E-02
†Greater or equal to 10,000 ppmv		

Conversions:
B: 0.04246 CH_4 density lb/scf
F: 2.20462262 lb/kg

Total Hydrocarbon Emission Factors for Processing, Transmission, and Underground Storage

Leaker Emissions Factors –Compressor Components, Non-Compressor Components, Gas Service

Methodology
Several leaker emission factors for the processing segment, such as open-ended lines before the de-methanizer for reciprocating compressors, did not have sufficient data points to justify a representative emission factor. To eliminate this issue, the segregation of components into reciprocating versus centrifugal and before the de-methanizer versus after the de-methanizer was eliminated.

In addition, the leaker emission factors from transmission were combined with those from processing. Equipment leak emissions from transmission compressors and processing compressors are similar because they are comparable in size and discharge pressure. Compressors in processing either inject residue gas into high pressure transmission pipelines or pressurize large volumes of production gas for processing facility processes.

The same LEFs can also be used for compressor related components in underground natural gas storage because compressors in this sector have a large throughput and inject gas at high pressure into the ground or into transmission pipelines. The final emission factors were corrected to 68˚F and 14.7 psia per the definition of "standard conditions" set forth in subpart A of Title 40 CFR 98.

[40] EPA. *Protocol for Equipment Leak Emission Estimates*. Emission Standards Division. U.S. EPA. SOCMI Table 2-7. November 1995.

Component EF, scf/hour/component = (Leak rate, Mscf/day/component) * (**E**) / (**C**)

Component Name	Emission Factor (scf/hour/component)
Leaker Emission Factors – Compressor Components, Gas Service	
Valve	15.07
Connector	5.68
Open-ended Line	17.54
Pressure Relief Valve	40.27
Meter	19.63
Leaker Emission Factors – Non -Compressor Components, Gas Service	
Valve	6.52
Connector	5.80
Open-ended Line	11.44
Pressure Relief Valve	2.04
Meter	2.98

Conversions:
C: 24 hours / day
E: 1000 scf / Mscf

Methane Emission Factors for LNG Terminals

Leaker Emission Factors – LNG Terminals Components, LNG Service

Methodology
See methodology for Leaker Emission Factors – LNG Storage Components, LNG Service for LNG Storage[40].

Methane Emission Factors for Distribution

Leaker Emission Factors – Above Grade M&R Stations Components, Gas Service

Methodology
Gas distribution meter/regulator station emissions are drawn from: *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*[38] and *Measurement of Natural Gas Emissions from the Canadian Natural Gas Transmission and Distribution Industry*[39].

Component EF, scf/hour/component = (Gas Distribution Meter/Regulator Station Emissions, kg/h/src) * (**F**) / (**B**)

Component Name	Component EF, scf/hour/comp	Gas Distribution Meter/Regulator Station Emissions, kg/h/src
Connector	0.67	0.01292

Block Valve	1.49	0.02872
Control Valve	3.94	0.07581
Pressure Relief Valve	5.24	0.1009
Orifice Meter	0.46	0.0088
Other Meter	0.01	0.0002064
Regulator	2.14	0.04129
Open-Ended Line	6.01	0.1158

Conversions:
B: 0.04246 CH_4 density lb/scf
F: 2.20462262 lb/kg

Leaker Emission Factors – Distribution Mains and Services, Gas Service

Methodology
Emission factors for pipeline leaks (mains and services) are drawn from GRI's *Methane Emissions from the Natural Gas Industry*[41].

Component EF, scf/hour/leak = (Pipeline Leak, scf/leak-year) / (**G**)

Component Name	Component EF (Mains), scf/hour/leak	Pipeline Leak EF (Mains), scf/leak-yr	Component EF, (Services) scf/hour/leak	Pipeline Leak EF (Services), scf/leak-yr
Unprotected Steel	6.02	52748	2.33	20433
Protected Steel	2.38	20891	1.08	9438
Plastic	11.63	101897	0.35	3026
Copper			0.88	7684

Conversions:
G: 8,760 hours/year

NATURAL GAS EMISSION FACTORS FOR ONSHORE PRODUCTION

Onshore production	Emission Factor (scf/hour/component)
Leaker Emission Factors - All Components, Gas Service	
Valve	NA
Connector	NA
Open-ended Line	NA
Pressure Relief Valve	NA
Low-Bleed Pneumatic Device Vents	NA
Gathering Pipelines	NA
CBM Well Water Production	NA
Compressor Starter Gas Vent	NA
Conventional Gas Well Completion	NA

[41] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 9. Tables 8-9 and 9-4. June 1996. <www.epa.gov/gasstar/documents/emissions_report/9_underground.pdf>

Conventional Gas Well Workover	NA
Leaker Emission Factors - All Components, Light Crude Service[1]	
Valve	2.03
Connector	0.90
Open-ended Line	0.96
Pump	2.35
Other	2.31
Leaker Emission Factors - All Components, Heavy Crude Service[2]	
Valve	3.13
Flange	4.15
Connector (other)	1.38
Open-ended Line	1.48
Other	3.56

[1] Hydrocarbon liquids greater than or equal to 20˚API are considered "light crude"
[2] Hydrocarbon liquids less than 20˚API are considered "heavy crude"

TOTAL HYDROCARBON EMISSION FACTORS FOR PROCESSING

Processing[1]	Before De-Methanizer Emission Factor (scf/hour/component)	After De-Methanizer Emission Factor (scf/hour/component)
Leaker Emission Factors - Reciprocating Compressor Components, Gas Service		
Valve	15.88	18.09
Connector	4.31	9.10
Open-ended Line	17.90	10.29
Pressure Relief Valve	2.01	30.46
Meter	0.02	48.29
Leaker Emission Factors - Centrifugal Compressor Components, Gas Service		
Valve	0.67	2.51
Connector	2.33	3.14
Open-ended Line	17.90	16.17
Leaker Emission Factors - Other Components, Gas Service[2]		
Valve	6.42	
Connector	5.71	
Open-ended Line	11.27	
Pressure Relief Valve	2.01	
Meter	2.93	

METHANE EMISSION FACTORS FOR TRANSMISSION

Transmission	Emission Factor (scf/hour/component)
Leaker Emission Factors - All Components, Gas Service	
Connector	2.7
Block Valve	10.4

Control Valve	3.4
Compressor Blowdown Valve	543.5
Pressure Relief Valve	37.2
Orifice Meter	14.3
Other Meter	0.1
Regulator	9.8
Open-ended Line	21.5
Leaker Emission Factors - Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	NA

[1] Emission Factor is in units of "scf/hour/mile"

METHANE EMISSION FACTORS FOR UNDERGROUND STORAGE

Underground Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors - Storage Station, Gas Service	
Connector	0.96
Block Valve	2.02
Control Valve	3.94
Compressor Blowdown Valve	66.15
Pressure Relief Valve	19.80
Orifice Meter	0.46
Other Meter	0.01
Regulator	1.03
Open-ended Line	6.01
Leaker Emission Factors - Storage Wellheads, Gas Service	
Connector	NA
Valve	NA
Pressure Relief Valve	NA
Open-ended Line	NA
Leaker Emission Factors - Other Components, Gas Service	
Low-Bleed Pneumatic Device Vents	NA

TOTAL HYDROCARBON EMISSION FACTORS FOR PROCESSING, TRANSMISSION, AND, UNDERGROUND STORAGE

Processing, Transmission, and Underground Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors – Compressor Components, Gas Service	
Valve	15.07
Connector	5.68
Open-Ended Line	17.54
Pressure Relief Valve	40.27
Meter	19.63
Leaker Emission Factors – Non-compressor Components , Gas Service	
Valve	6.52
Connector	5.80
Open-Ended Line	11.44

Pressure Relief Valve	2.04
Meter	2.98

[1]Valves include control valves, block valves, and regulator valves.

METHANE EMISSION FACTORS FOR LNG STORAGE

LNG Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors - LNG Storage Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other	1.77
Leaker Emission Factors - LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor	NA

METHANE EMISSION FACTORS FOR LNG TERMINALS

LNG Terminals	Emission Factor (scf/hour/component)
Leaker Emission Factors - LNG Terminals Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other	1.77
Leaker Emission Factors - LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor	NA

METHANE EMISSION FACTORS FOR DISTRIBUTION

Distribution	Emission Factor (scf/hour/component)
Leaker Emission Factors - Above Grade M&R Stations Components, Gas Service	
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.270
Orifice Meter	0.212
Regulator	26.131
Open-ended Line	1.69
Leaker Emission Factors - Below Grade M&R Stations Components, Gas Service	
Below Grade M&R Station, Inlet Pressure > 300 psig	NA
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	NA
Below Grade M&R Station, Inlet Pressure < 100 psig	NA
Leaker Emission Factors - Distribution Mains, Gas Service[1]	
Unprotected Steel	6.02

Protected Steel	2.38
Plastic	11.63
Cast Iron	NA
Leaker Emission Factors - Distribution Services, Gas Service[1]	
Unprotected Steel	2.33
Protected Steel	1.08
Plastic	0.35
Copper	0.88

[1] Emission Factor is in units of "scf/hour/leak"

Summary

This Appendix provides leaker emissions factors that can be applied to any individual emissions source which meets the leak detection definition in a leak detection survey. These emissions factors provide an estimate of real emissions as opposed to potential emissions since they are applied only to leaking emissions sources. However, it must be noted that these leaker emissions factors assume that any emissions source found leaking has been leaking for the duration of an entire year.

Appendix G: Development of population emission factors

Natural Gas Emission Factors for Onshore Production

Whole Gas Population Emission Factors – All Components, Gas Service

Methodology
The well counts and emission factors were taken from GRI's *Methane Emissions from the Natural Gas Industry*[42]. The emission factors for each source are calculated using gas production for the Eastern and Western United States. The average methane content of produced natural gas is assumed to be 78.8%.

Eastern/Western U.S. Component EF, scf/hour/component = (EF Eastern/Western U.S., mscf/yr) * (**A**) * (**B**) / (**C**) / (**D**)

Component	Eastern U.S. EPA/GRI EF (mscf CH_4/year)	Eastern U.S. Subpart W EF (scf natural gas/hour)
Valve	0.184	0.027
Connector	0.024	0.004
Open-Ended Line	0.420	0.062
Pressure Relief Valve	0.279	0.041

Component	Western U.S. EPA/GRI EF (mscf CH_4/year)	Western U.S. Subpart W EF (scf natural gas/hour)
Valve	0.835	0.123
Connector	0.114	0.017
Open-Ended Line	0.215	0.032
Pressure Relief Valve	1.332	0.196

Conversions:
A: 1,000 scf/mscf
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
C: 8,760 hours/year
D: 78.8% methane by volume in produced natural gas

"High Continuous Bleed Pneumatic Device Vents" Methodology
Methane emissions per pneumatic device are from API's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*[43]. The average methane content of natural gas is assumed to be 78.8%.

48.1 scf/hour/component EF = (**896** [scfd CH_4/pneumatic devises, high bleed]) * (**B**) / (**D**) / (**E**)

[42] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 8. June 1996. <www.epa.gov/gasstar/documents/emissions_report/8_equipmentleaks.pdf>
[43] API. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*. American Petroleum Institute. Table 5-15, page 5-68. August 2009.

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 78.8% – production quality of natural gas (% methane) [44]
E: 24 hours/day

"Low Continuous Bleed Pneumatic Device Vents" Methodology
Methane emissions per pneumatic device are from API's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*[43]. The average methane content of natural gas is assumed to be 78.8%.

1.80 scf/hour/component EF = (**33.4** [scfd CH_4/pneumatic devises, low bleed]) * (**B**) / (**D**) / (**E**)

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 78.8% – production quality of natural gas (% methane)
E: 24 hours/day

"Intermittent Bleed Pneumatic Device Vents" Methodology
Methane emissions per pneumatic device are from API's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*[43]. The average methane content of natural gas is assumed to be 78.8%.

17.4 scf/hour/component EF = (**323** [scfd CH_4/pneumatic devises, low bleed]) * (**B**) / (**D**) / (**E**)

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 78.8% – production quality of natural gas (% methane)[44]
E: 24 hours/day

"Pneumatic Pumps" Methodology
Methane emissions per pneumatic pump are from GRI's *Methane Emissions from the Natural Gas Industry*[45]. The average methane content of natural gas is assumed to be 78.8%.

13.3 scf CH_4/hour/component EF = (**248** [scfd CH_4/pneumatic devises, low bleed]) * (**B**) / (**D**) / (**E**)

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[44] GRI. "Vented and Combustion Source Summary," *Methane Emissions from the Natural Gas Industry,* U.S. EPA, Volume 6, Appendix A, page A-2.
[45] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 13. Tables 4-4. June 1996. <http://epa.gov/gasstar/documents/emissions_report/13_chemical.pdf>.

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 78.8% – production quality of natural gas (% methane)[46]
E: 24 hours/day

Population Emission Factors – All Components, Light Crude Service

Methodology
Average emissions factors by facility type were taken from API's *Emission Factors for Oil and Gas Production* Operations.[47] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."

Component EF, scf/hour/component = (Average Emissions Factors by Facility Type, lb/component-day) * (**B**) / (**E**) / (**F**)

Component Name	Component EF, scf/hr/comp	Average EF by Facility Type, lb/component-day
Valve	0.04	7.00E-02
Flange	0.002	4.07E-03
Connector	0.005	8.66E-03
Open-Ended Line	0.04	6.38E-02
Pump	0.01	1.68E-02
Other	0.23	3.97E-01

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 24 hours/day
F: 0.072 gas density lb/scf – assumes a gas composition of 61.2% methane, 20% ethane, 10% propane, 5% butane, and 3.8% pentanes+

Population Emission Factors – All Components, Heavy Crude Service

Methodology
Average emissions factors by facility type were taken from API's *Emission Factors for Oil and Gas Production Operations*[48]. Hydrocarbon liquids less than 20°API are considered "heavy crude." The methane content of associated natural gas with onshore light crude is 94.2% from the same study.

[46] GRI. "Vented and Combustion Source Summary," *Methane Emissions from the Natural Gas Industry,* U.S. EPA, Volume 6, Appendix A, page A-2.
[47] API. *Emission Factors for Oil and Gas Production Operations*. Table 9, page 10. API Publication Number 4615. January 1995.
[48] API. *Emission Factors for Oil and Gas Production Operations*. API Publication Number 4615. page ES-3, Table ES-4, January 1995.

Component EF, scf/hour/component = (Average Emissions Factors by Facility Type, lb/component-day) * (**B**) / (**D**) / (**F**)

Component Name	Component EF, scf/hr/comp	Average EF by Facility Type, lb/component-day
Valve	0.0004	6.86E-04
Flange	0.0002	1.16E-03
Connector (Other)	0.0004	4.22E-04
Open-Ended Line	0.004	8.18E-03
Other	0.002	3.70E-03

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 24 hours/day
F: 0.072 gas density lb/scf – assumes a gas composition of 61.2% methane, 20% ethane, 10% propane, 5% butane, and 3.8% pentanes+

Methane Emission Factors For Processing

Population Emission Factors – All Components, Gas Service

There are no population emission factors in subpart W for the onshore natural gas processing segment.

Methane Emission Factors for Transmission

Population Emission Factors – All Components, Gas Service

Gas transmission facility emission factors were taken from the *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*[49]. "Connector" includes flanges, threaded connections, and mechanical couplings. "Block Valve" accounts for emissions from the stem packing and the valve body, and it applies to all types of block valves (e.g., butterfly, ball, globe, gate, needle, orbit, and plug valves). Leakage past the valve seat is accounted for the Open-Ended Line emission category. Leakage from the end connections is accounted for by the connector category (i.e., one connector for each end). "Control Valve" accounts for leakage from the stem packing and the valve body. Emissions from the controller and actuator are accounted for by the Instrument Controller and Open-Ended Line categories respectively. This factor applies to all valves with automatic actuators (including fuel gas injection valves on the drivers of reciprocating compressors). "Orifice Meter" accounts for emissions from the orifice changer. Emissions from sources on pressure tap lines etc. are not included in the factor (i.e., these emissions must be calculated separately).

[49] CEPEI. *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*. May 25, 1998.

"Other Meter" accounts for emissions from other types of gas flow meters (e.g., diaphragm, ultrasonic, roots, turbine, and vortex meters).

Component EF, scf/hour/component = (Gas Transmission Facility Emissions, kg/h/src) * (**B**) * (**I**) / (**F**)

Component Name	Component EF, scf/hour/comp	Gas Transmission Facility Avg. Emissions, kg/hr/src
Connector	0.01	2.732E-04
Block Valve	0.11	2.140E-03
Control Valve	1.04	1.969E-02
Pressure Relief Valve	14.74	2.795E-01
Orifice Meter	0.18	3.333E-03
Other Meter	0.0005	9.060E-06
Regulator	0.17	3.304E-03
Open-Ended Line	4.40	8.355E-02

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
F: 0.04246 CH_4 density lb/scf
I: 2.20462262 lb/kg

<u>Population Emission Factors – Other Components, Gas Service</u>

"Low Continuous Bleed Pneumatic Device Vents" Methodology
Methane emissions per pneumatic device are from API's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*[43]. The average methane content of natural gas is assumed to be 78.8%.

1.41 scf/hour/component EF = (**33.4** [scfd CH_4/pneumatic devises, low bleed]) * (**B**) * (**J**) / (**D**) / (**E**)

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 78.8% – production quality of natural gas (% methane) from: "Vented and Combustion Source Summary," *Methane Emissions from the Natural Gas Industry,* U.S. EPA, Volume 6, Appendix A, page A-2.
E: 24 hours/day
J: 93.4% – pipeline quality natural gas (% methane) from: "Vented and Combustion Source Summary," *Methane Emissions from the Natural Gas Industry,* U.S. EPA, Volume 6, Appendix A, page A-2.

"High Continuous Bleed Pneumatic Device Vents" Methodology

Methane emissions per pneumatic device are from GRI's *Methane Emissions from the Natural Gas Industry*[50]. The average methane content of natural gas is assumed to be 78.8%.

18.8 scf/hour/component EF = (**162,197** [scfy CH_4/pneumatic devises, low bleed]) * (**B**) / (**C**)

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
C: 8,760 hours/year

"Intermittent Bleed Pneumatic Device Vents" Methodology
Methane emissions per pneumatic device are from GRI's *Methane Emissions from the Natural Gas Industry*[50]. The average methane content of natural gas is assumed to be 78.8%.

18.8 scf/hour/component EF = (**162,197** [scfy CH_4/pneumatic devises, low bleed]) * (**B**) / (**C**)

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
C: 8,760 hours/year

Methane Emission Factors for Underground Storage

Population Emission Factors – Storage Station, Gas Service

Methodology
See methodology for "Population Emission Factors – All Components, Gas Service" for Transmission.

Population Emission Factors – Storage Wellheads, Gas Service

Methodology
Emission factors for injection/withdrawal wellheads are from GRI's *Methane Emissions from the Natural Gas Industry*[42].

Component EF, scf/hour/component = (Injection/Withdrawal Wellhead) (**A**) * (**B**) / (**C**)

Component Name	Component EF, scf/hr/comp	Injections/Withdrawal Wellhead, Mcf/yr
Connector	0.01	0.125

[50] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 12. Page 52. June 1996. <http://epa.gov/gasstar/documents/emissions_report/12_pneumatic.pdf>.

Valve	0.10	0.918
Pressure Relief Valve	0.17	1.464
Open-Ended Line	0.03	0.237

Conversions:
A: 1,000 scf/mscf
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
C: 8,760 hours/year

Population Emission Factors – Other Components, Gas Service

Methodology
"Low Continuous Bleed Pneumatic Device Vents" Methodology
See "Low Continuous Bleed Pneumatic Device Vents" Methodology for Population Emission Factors – Other Components, Gas Service for Transmission.

"High Continuous Bleed Pneumatic Device Vents" Methodology
See "High Continuous Bleed Pneumatic Device Vents" Methodology for Population Emission Factors – Other Components, Gas Service for Transmission.

"Intermittent Bleed Pneumatic Device Vents" Methodology
See "Intermittent Bleed Pneumatic Device Vents" Methodology for Population Emission Factors – Other Components, Gas Service for Transmission.

Methane Emission Factors for LNG Storage

Population Emission Factors – LNG Storage Components, LNG Service

Methodology
Component emission factors are from EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks*[51]. The emission factors were adjusted by an assumed average methane content of 93.4% by volume.

Component EF, scf/hour/component = (Component EF, Mscf/comp-yr) (**B**) * (**I**) / (**F**)

Component Name	Component EF, scf/hour/comp	Component EF, Mscf/comp-yr
Valve	0.10	0.867
Open-ended Line	1.30	11.2
Connector	0.02	0.147
PRV	0.72	6.2

Conversions:

[51] EPA. *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2006*. Available online at <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.

B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
F: 0.04246 CH_4 density lb/scf
I: 2.20462262 lb/kg

Population Emission Factors – LNG Storage Compressor, Gas Service

"Vapor Recovery Compressor" Methodology
The methane emissions per compressor are from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*[51].

4.23 scf/hour/component EF = (**100** scfd CH_4/compressor) * (**B**) / (**D**)
Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
D: 24 hours/day

Methane Emission Factors for LNG Terminals

Population Emission Factors – LNG Terminals Components, LNG Service

Methodology
See methodology for Population Emission Factors – LNG Storage Components, LNG Service for LNG Storage.

Population Emission Factors – LNG Terminals Compressor, Gas Service

Methodology
See "Vapor Recovery Compressor" Methodology for Population Emission Factors – LNG Storage Compressor, Gas Service for LNG Storage.

Methane Emission Factors for Distribution

Population Emission Factors – Above Grade M&R Stations Components, Gas Service

Methodology
Gas distribution meter/regulator station average emissions from: Gas transmission facility emissions are from the *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*[49]. "Connector" includes flanges, threaded connections, and mechanical couplings. "Block Valve" accounts for emissions from the stem packing and the valve body, and it applies to all types of block valves (e.g., butterfly, ball, globe, gate, needle, orbit, and plug valves). Leakage past the valve seat is accounted for the Open-Ended Line emission category. Leakage from the end connections is accounted for by the connector category

(i.e., one connector for each end). "Control Valve" accounts for leakage from the stem packing and the valve body. Emissions from the controller and actuator are accounted for by the Instrument Controller and Open-Ended Line categories respectively. This factor applies to all valves with automatic actuators (including fuel gas injection valves on the drivers of reciprocating compressors). "Orifice Meter" accounts for emissions from the orifice changer. Emissions from sources on pressure tap lines etc. are not included in the factor (i.e., these emissions must be calculated separately). "Other Meter" accounts for emissions from other types of gas flow meters (e.g., diaphragm, ultrasonic, roots, turbine, and vortex meters).

Component EF, scf/hour/component = (Gas Distribution Meter/Regulator Station Emissions, kg/h/src) * (**B**) * (**I**) / (**F**)

Component Name	Component EF, scf/hour/comp	Gas Distribution Meter/Regulator Station Avg. Emissions, kg/h/src
Connector	5.79E-03	1.098E-04
Block Valve	5.85E-02	1.109E-03
Control Valve	1.04E+00	1.969E-02
Pressure Relief Valve	8.78E-01	1.665E-02
Orifice Meter	1.76E-01	3.333E-03
Other Meter	4.78E-04	9.060E-06
Regulator	1.01E-01	1.915E-03
Open-Ended Line	4.39E+00	8.355E-02

Conversions:
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
F: 0.04246 CH_4 density lb/scf
I: 2.20462262 lb/kg

Population Emission Factors – Below Grade M&R Stations Components, Gas Service

Methodology
Average emission factors are from GRI's *Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution*[52]. (Converted to 68˚F)

Below Grade M&R Station, Inlet Pressure > 300 psig: 1.32 scf/hour/station EF

Below Grade M&R Station, Inlet Pressure 100 to 300 psig: 0.20 scf/hour/station EF

Below Grade M&R Station, Inlet Pressure < 100 psig: 0.10 scf/hour/station EF

Population Emission Factors – Distribution Mains and Services, Gas Service

Methodology

[52] GRI. *Methane Emissions from the Natural Gas Industry*. Volume 10. Table 7-1. June 1996. <www.epa.gov/gasstar/documents/emissions_report/10_metering.pdf>.

Emission factors for pipeline leaks (mains and service) are from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*[53]

Component EF, scf/hour/service = (Pipeline Leak mscf/mile/year) (**A**) * (**B**) / (**C**)

Component Name	Component EF (Mains), scf/hr/service	Pipeline Leak EF (Mains), Mscf/mile-yr	Component EF (Services), scf/hr/service	Pipeline Leak EF (Services), Mscf/mile-yr
Unprotected Steel	12.77	110.19	0.19	1.70
Protected Steel	0.36	3.07	0.02	0.18
Plastic	1.15	9.91	0.001	0.01
Cast Iron	27.67	238.7		
Copper			0.03	0.25

Conversions:
A: 1,000 scf/mscf
B: 1.015 = (68+459.67)/(60+459.67) = conversion from 60˚F to 68˚F per subpart A definition of standard conditions
C: 8,760 hours/year

Nitrous Oxide Emission Factors for Gas Flaring

Population Emission Factors – Gas Flaring

Methodology
Emission factors are from API's *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*.

Gas Production: 5.90E-07 metric tons/MMcf gas production or receipts EF

Sweet Gas Processing: 7.10E-07 metric tons/MMcf gas production or receipts EF

Sour Gas Processing: 1.50E-06 metric tons/MMcf gas production or receipts EF

Conventional Oil Production: 1.00E-04 metric tons/barrel conventional oil production EF

Heavy Oil Production: 7.30E-05 metric tons/barrel heavy oil production EF

Summary
This Appendix provides population emissions factors for potential emissions sources. These population emissions factors could be used in conjunction with population counts that make it more cost effective in estimating emissions. However, these population emissions factors estimate potential emissions as the percentage of emissions sources leaking may or may not

[53] EPA. *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2007*. Available online at <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.

be the same as the assumption made when developing the emissions factors. Also, the population emissions factors assume that a subset of leaking emission sources is leaking continuously throughout the year.

Appendix H: Glossary

The following definitions are based on common industry terminology for the respective equipment, technologies, and practices.

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

Acid gas means hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal unit.

Acid gas removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent emissions mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Air injected flare means a flare in which air is blown into the base of a flare stack to induce complete combustion of gas.

Basin means geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see §98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see §98.7).

Blowdown vent stack emissions mean natural gas and/or CO_2 released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas or CO_2 by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

Centrifugal compressor dry seal emissions mean natural gas or CO_2 released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seal degassing vent emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO_2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Component means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Continuous bleed means a continuous flow of pneumatic supply gas to the process measurement device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

Compressor means any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas or CO_2 and discharging significantly higher pressure natural gas or CO_2.

Condensate means hydrocarbon and other liquid, including both water and hydrocarbon liquids, separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions.

Dehydrator means a device in which a liquid absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent emissions means natural gas and CO_2 released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator to the atmosphere or a flare, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

De-methanizer means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream.

Desiccant means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption or absorption. Desiccants include activated alumina, pelletized

calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent or absorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface or absorbed and dissolves the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto or absorbed into the desiccant material, leaving the dry gas to exit the contactor.

Engineering estimation means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Equipment leak means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Equipment leak detection means the process of identifying emissions from equipment, components, and other point sources.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Natural gas distribution facility means the collection of all distribution pipelines, metering stations, and regulating stations that are operated by a Local Distribution Company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Onshore petroleum and natural gas production facility means all petroleum or natural gas equipment on a well pad or associated with a well pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in §98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Farm Taps are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. The gas may or may not be metered, but always does not pass through a city gate station. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

Field means oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List 2008, DOE/EIA 0370(08) (incorporated by reference, see §98.7).

Flare stack emissions means CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in flares.

Flare combustion efficiency means the fraction of hydrocarbon gas, on a volume or mole basis, that is combusted at the flare burner tip.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Gas well means a well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.

High-bleed pneumatic devices are automated, continuous bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of 6 standard cubic feet per hour.

Intermittent bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and –pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

LNG boil-off gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Low-bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Offshore means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.

Oil well means a well completed for the production of crude oil from at least one oil zone or reservoir.

Onshore petroleum and natural gas production owner or operator means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued, which operates an onshore petroleum and/or natural gas production facility (as described in §98.230(a)(2). Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reciprocating compressor means a piece of equipment that increases the pressure of a process natural gas or CO_2 by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas or CO_2 that escapes to the atmosphere.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Residue Gas and Residue Gas Compression mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

Sales oil means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer tank gauge.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Sour natural gas means natural gas that contains significant concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

Sweet Gas is natural gas with low concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

Transmission pipeline means high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

United States means the 50 States, the District of Columbia, the Commonwealth of Puerto Rico, American Samoa, the Virgin Islands, Guam, and any other Commonwealth, territory or possession of the United States, as well as the territorial sea as defined by Presidential Proclamation No. 5928.

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

Vaporization unit means a process unit that performs controlled heat input to vaporize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

Well completions means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture or re-fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Well workover means the process(es) of performing one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production. This process also includes high-rate flowback of injected gas, water, oil, and proppant used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. Wellhead equipment includes all equipment, permanent and portable, located on the improved land area (i.e. well pad) surrounding one or multiple wellheads.

Wet natural gas means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas."

Appendix I: References

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To: Weitz, Melissa[Weitz.Melissa@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]
From: Gunning, Paul
Sent: Fri 12/1/2017 7:36:10 PM
Subject: FW: GHG Inventory

FYI.....I will make sure you are on the invite. Also, please let me know if you have any

Ex. 5 - Deliberative Process

From: Gunning, Paul
Sent: Friday, December 01, 2017 2:31 PM
To: Krieger, Jackie <Krieger.Jackie@epa.gov>
Cc: Kocchi, Suzanne <Kocchi.Suzanne@epa.gov>
Subject: RE: GHG Inventory

Jackie – we should make sure that Mark D., Bill I., and Melissa Weitz are on the invite. Melissa is the most critical.

From: Krieger, Jackie
Sent: Friday, December 01, 2017 2:10 PM
To: Gunning, Paul <Gunning.Paul@epa.gov>
Cc: Kocchi, Suzanne <Kocchi.Suzanne@epa.gov>
Subject: FW: GHG Inventory

Hi Paul, Suzie. See this meeting request below. How do you want to staff it? In addition to you and Sarah. Emily now knows that it is not OAQPS.

From: Atkinson, Emily
Sent: Friday, December 01, 2017 12:12 PM
To: Koerber, Mike <Koerber.Mike@epa.gov>; South, Peter <South.Peter@epa.gov>
Subject: FW: GHG Inventory

Right now I just have Mike and Steve on this briefing – please advise if anyone else needs to be added and if you all recommend we do a prebrief for Mandy. And FYI – this is a Mandy meeting and it would not include Bill.

From: Atkinson, Emily
Sent: Friday, December 01, 2017 12:05 PM
To: Hilary Moffett <moffetth@api.org>
Subject: RE: GHG Inventory

Hi Hillary,

Mandy Gunasekara has reviewed this request and asked that I setup a 45 minute in person meeting to include staff from OAQPS, Alex Dominguez and David Harlow.

It looks like we could fit this in on Friday, December 15 at 4:00pm.

Please advise if this could work on your end.

Emily

Emily Atkinson
Management Analyst/Office Manager

Immediate Office of the Assistant Administrator
Office of Air and Radiation, USEPA
Room 5412B, 1200 Pennsylvania Avenue NW
Washington, DC 20460
Voice: 202-564-1850
Email: atkinson.emily@epa.gov

From: Hilary Moffett [mailto:moffetth@api.org]
Sent: Wednesday, November 29, 2017 2:05 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Atkinson, Emily <Atkinson.Emily@epa.gov>
Subject: FW: GHG Inventory

Ex. 6 - Personal Privacy

Just wanted to circle back on this email. I just want to make sure you guys are aware of what the career team is doing on the inventory and how this could inaccurately depict emissions. This data is so important to all that EPA does, so we want to make sure it fairly represents all the effort to decrease emissions. Let me know if you have some time to chat. Alex mentioned that Emily has taken on the role of helping manage your schedule, so I've cc'd her here. I know we're asking a lot of you guys right now, so I appreciate any time you can find.

Thanks,

Hilary

From: Hilary Moffett
Sent: Monday, November 20, 2017 11:20 AM
To: gunasekara.mandy@epa.gov
Subject: GHG Inventory

Hey Mandy,

Ex. 6 - Personal Privacy

I wanted to flag an issue that is pretty important as we look toward next spring. We expect to see the the GHG inventory released in April. Some changes have been made to what is included in the inventory (namely the inclusion of gathering and boosting) that will create the appearance of increased methane emissions. We worry about how the changes here will misinform the public perception of the industry and the great work we are doing to lower emissions. Is this issue on your radar? If not, would you have Tim the week of December 11-15 for a group to come explain why the changes were made, what the outcome will be, and perhaps how we can work to preempt the inevitable issues that these changes will create.

Let me know how we can be helpful.

Thanks,

Hilary

To: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Hogan, Sean[Hogan.Sean@epa.gov]
Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]; Tang, Natalie[Tang.Natalie@epa.gov]
From: McKittrick, Alexis
Sent: Mon 11/16/2015 11:11:24 PM
Subject: RE: GHG Data Workshop slides - for your review
GHGDataWorkshop_GHGRP Distribution_segment_11_16_15.pptx
GHGDataWorkshop_GHGRP Onshore Production 11_16_15.pptx
GHGDataWorkshop_GHGRP Transmission_storage 11_16_15.pptx
GHGDataWorkshop_GHGRP Processing 11_16_15.pptx
GHGDataWorkshop_Overview of GHGRP 11_12_15.pptx

Thanks for your comments, Mark. Attached are the revised versions (except the deck of overview slides, which are attached but have not changed). Let me know if you have any final edits!

Best,

Alexis

From: DeFigueiredo, Mark
Sent: Monday, November 16, 2015 1:41 PM
To: McKittrick, Alexis <McKittrick.Alexis@epa.gov>; Hogan, Sean <Hogan.Sean@epa.gov>
Cc: Weitz, Melissa <Weitz.Melissa@epa.gov>
Subject: RE: GHG Data Workshop slides - for your review

Ex. 5 - Deliberative Process

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Mark de Figueiredo, J.D., Ph.D.

Climate Change Division

U.S. Environmental Protection Agency

Office: (202) 343-9928

Mobile: (202) 251-4951

Email: defigueiredo.mark@epa.gov

From: DeFigueiredo, Mark
Sent: Monday, November 16, 2015 1:28 PM
To: McKittrick, Alexis <McKittrick.Alexis@epa.gov>; Hogan, Sean <Hogan.Sean@epa.gov>
Cc: Weitz, Melissa <Weitz.Melissa@epa.gov>
Subject: RE: GHG Data Workshop slides - for your review

Ex. 5 - Deliberative Process

From: McKittrick, Alexis
Sent: Friday, November 13, 2015 4:47 PM
To: Hogan, Sean <Hogan.Sean@epa.gov>; DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>
Cc: Weitz, Melissa <Weitz.Melissa@epa.gov>
Subject: FW: GHG Data Workshop slides - for your review

Mark – Please feel free to send me additional tweaks on these presentations. I just needed to get them over to Alison & Bruce. I am also happy to talk through which of your edits I did / did not take and why.

Sean & Mark – Below are my thoughts on the presenters for these 5 slide decks next Thursday at the GHG Data Workshop. Let me know if you are okay with this or have other suggestions.

GHGRP / Subpart W overview – Alexis

Distribution segment – Natalie

Transmission / storage – Alexis

Processing – Mark (or Alexis, if Mark doesn't want to present)

Production - Alexis

I hope you both have a great weekend,

Alexis

From: McKittrick, Alexis
Sent: Friday, November 13, 2015 1:42 PM
To: Moore, Bruce <Moore.Bruce@epa.gov>; Davis, Alison <Davis.Alison@epa.gov>
Cc: DeFigueiredo, Mark <defigueiredo.mark@epa.gov>; Tang, Natalie <Tang.Natalie@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>
Subject: GHG Data Workshop slides - for your review

Bruce & Alison,

Attached are the five mini-presentations from GHGRP for the GHG Data Workshop in Pittsburgh next Thursday. (This is separate from the Gas Star workshop on Tuesday and Wednesday.) While five presentations may look daunting, none of them are longer than about a dozen slides. Also, the structure is repeated for each of the segment-specific presentations – just the actual data / numbers change.

Please let me know by lunchtime next Wednesday if you have any concerns or edits. As always, thank you so much for your review!

Best,

Alexis

Alexis McKittrick, Ph.D.

Climate Change Division

U.S. Environmental Protection Agency

Phone: 202-343-9153

E-mail: mckittrick.alexis@epa.gov

To: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Franklin, Pamela[Franklin.Pamela@epa.gov]
Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; Bylin, Carey[Bylin.Carey@epa.gov]
From: McKittrick, Alexis
Sent: Tue 5/12/2015 12:48:31 PM
Subject: RE: Discussion w/GTI on emissions factors & methane sensors / Call-in: 1-8 Ex. 6 - Personal Privacy
Code: Ex. 6 - Personal Privacy

Yes, I'll be there.

Alexis

From: DeFigueiredo, Mark
Sent: Tuesday, May 12, 2015 8:48 AM
To: Franklin, Pamela
Cc: Weitz, Melissa; Irving, Bill; Waltzer, Suzanne; Bylin, Carey; McKittrick, Alexis
Subject: Re: Discussion w/GTI on emissions factors & methane sensors / Call-in: Ex. 5 - Deliberative Process
Ex. 6 - Personal Privacy

I believe Alexis is planning to attend the GTI meeting as well.

Sent from my iPhone

On May 12, 2015, at 6:46 AM, Franklin, Pamela <Franklin.Pamela@epa.gov> wrote:

All,

Just spoke to Suzie K and trying to make sure that we have sufficient staffing for this meeting this afternoon.

Suzie W – will you be calling in?

Melissa and Bill – are you planning to go?

I am only planning to attend if necessary – e.g., if we don't have enough people in the room without me.

Thanks

Pamela

<Discussion w GTI on emissions factors & methane sensors Call-in Ex. 5 - Deliberative Process
Ex. 5 - Deliberative Process ics>

To: Gunning, Paul[Gunning.Paul@epa.gov]
Cc: Hight, Cate[Hight.Cate@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Harvey, Reid[Harvey.Reid@epa.gov]; Birnbaum, Rona[Birnbaum.Rona@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Creason, Jared[Creason.Jared@epa.gov]
From: Fawcett, Allen
Sent: Fri 5/8/2015 6:11:17 PM
Subject: Re: Role of natural gas in meeting an electric sector emissions reduction strategy and effects on greenhouse gas emissions

Great, Jared and I are looking at it too.

_____
Allen A. Fawcett, Ph.D.
Chief, Climate Economics Branch
U.S. EPA
O: 202 343-9436
C: 202 412-5116

On May 8, 2015, at 2:10 PM, Gunning, Paul <Gunning.Paul@epa.gov> wrote:

> Thanks Allen. FYI. I think Melissa might be looking at it already from the emissions perspective
>
> Paul
>
> Paul M Gunning
> 202-251-1436
>
> On May 8, 2015, at 2:01 PM, Fawcett, Allen <Fawcett.Allen@epa.gov> wrote:
>
>> Will do.
>>
>> _____
>> Allen A. Fawcett, Ph.D.
>> Chief, Climate Economics Branch
>> U.S. EPA
>> O: 202 343-9436
>> C: 202 412-5116
>>
>> On May 8, 2015, at 1:58 PM, Gunning, Paul <Gunning.Paul@epa.gov> wrote:
>>
>>> Allen
>>>
>>> I am in transit and it looks like Sarah is hoping for a quick read on this paper (for

CPP and methane implications. Can u please work with available folks to pull something together?

Thanks

Paul M Gunning
202-251-1436

Begin forwarded message:

From: "Dunham, Sarah" <Dunham.Sarah@epa.gov>
Date: May 8, 2015 at 1:16:20 PM EDT
To: "Gunning, Paul" <Gunning.Paul@epa.gov>, "Harvey, Reid" <Harvey.Reid@epa.gov>
Cc: "Birnbaum, Rona" <Birnbaum.Rona@epa.gov>
Subject: RE: Role of natural gas in meeting an electric sector emissions reduction strategy and effects on greenhouse gas emissions

Ex. 5 - Deliberative Process

Sent from my Windows Phone

From: Gunning, Paul
Sent: 5/8/2015 11:50 AM
To: Harvey, Reid; Dunham, Sarah
Cc: Birnbaum, Rona
Subject: FW: Role of natural gas in meeting an electric sector emissions reduction strategy and effects on greenhouse gas emissions

FYI.....an unexpected paper from ORD (Frank P).....Reid we will loop your folks in as well. We are trying to get more info. on where/if they are planning on publishing/presenting this.....

ABSTRACT

Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

Paul

From: Birnbaum, Rona
Sent: Friday, May 08, 2015 8:59 AM
To: Irving, Bill; Fawcett, Allen; Franklin, Pamela; Karimjee, Anhar
Cc: Gunning, Paul; Kocchi, Suzanne
Subject: Fwd: Role of natural gas in meeting an electric sector emissions reduction strategy and effects on greenhouse gas emissions

...here we go...at least we're seeing it before submission.

Lisa is circulating to the oil and gas team to provide comments.

Sent from my iPhone

Begin forwarded message:

From: "Princiotta, Frank" <Princiotta.Frank@epa.gov>
Date: May 7, 2015 at 4:21:08 PM EDT
To: "Birnbaum, Rona" <Birnbaum.Rona@epa.gov>, "Srivastava, Ravi" <Srivastava.Ravi@epa.gov>
Cc: "Sonich-Mullin, Cynthia" <Sonich-Mullin.Cynthia@epa.gov>, "Nunez, Carlos" <Nunez.Carlos@epa.gov>, "Costa, Dan" <Costa.Dan@epa.gov>, "McKinney, Doug"

<Mckinney.Douglas@epa.gov>, "Yelverton, William" <Yelverton.William@epa.gov>, "Lenox, Carol" <Lenox.Carol@epa.gov>, "Costa, Dan" <Costa.Dan@epa.gov>, "Sikdar, Subhas" <sikdar.subhas@epa.gov>

Subject: Role of natural gas in meeting an electric sector emissions reduction strategy and effects on greenhouse gas emissions

To: Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]
Cc: Franklin, Pamela[Franklin.Pamela@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Sarofim, Marcus[Sarofim.Marcus@epa.gov]
From: Gunning, Paul
Sent: Thur 6/4/2015 1:38:42 PM
Subject: Re: Preparation for Methane Panel Conference Call

Thanks u guys are the best!!

Paul M Gunning
202-251-1436

On Jun 4, 2015, at 9:21 AM, Waltzer, Suzanne <Waltzer.Suzanne@epa.gov> wrote:

Hi Paul,

Sorry for the delay. I have been having major computer problems this morning. Below is some additional input on the questions for your presentation today. I also included some

Ex. 5 - Deliberative Process

Thanks,

Suzie

Ex. 5 - Deliberative Process

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Ex. 5 - Deliberative Process

From: Gunning, Paul
Sent: Wednesday, June 03, 2015 4:21 PM
To: Waltzer, Suzanne; Franklin, Pamela
Subject: FW: Preparation for Methane Panel Conference Call

Sorry for the late hit on this, but I just got these questions. Is it possible to get short responses to me before the meeting tomorrow? Some of these are just fact questions. A short email is fine, nothing too fancy.

Thanks

From: Broome, Shannon S. [mailto:shannon.broome@kattenlaw.com]
Sent: Wednesday, June 03, 2015 3:58 PM
To: David Doniger; gretchen.kern@pxd.com; Gunning, Paul; Hargrove, Anne; lreiser@nrdc.org
Subject: RE: Preparation for Methane Panel Conference Call

All – in the spirit of just in time manufacturing, I am sending an outline following the discussion we had last week. If I have mischaracterized anything in terms of the progression, please let me know. If you have a concern with any question, please just reply all with suggestions. Also, you can suggest additional questions. No pride of authorship here. Just trying to cover the key issues. Gretchen – your knowledge on the sources will be incredibly valuable in terms of educating the audience on what these sources "look like" in the field.

Thank you again and I look forward to seeing everyone in the morning.

Overview of Panel on 111(b) and (d) and Methane

I. Introductions of Panelists (5 minutes) – Caveats – People are here to educate and unless they say that they are taking a specific position on behalf of their organization, please keep in mind that they are trying to provide a balanced analysis for the audience, not to stake out particular advocacy positions.

II. Brief Introduction by Shannon Broome, setting the stage regarding what EPA has done to date on the NSPS for this sector. (10-15 minutes)

III. A Few Words by David Doniger (10 minutes)

IV. A Few Words by Gretchen Kern (10 minutes)

V. Opportunity for Paul to speak briefly but he may have covered it all in his first presentation. (5 minutes)

VI. Q&A (30 minutes)

1. Opportunity: what is the "opportunity" for reductions here looking at the four areas that EPA outlined in its white papers last summer? (e.g. what are the significant sources of emissions in this sector)

2. What would the benefits or costs/practical implementation difficulties?

3. How does that square with the best system of emission reduction approach for NSPS and cost effectiveness?

4. What are the significant sources of methane emissions in the upstream sector?

5. One legal issue that keeps coming up is the endangerment finding question. Does EPA need to make an endangerment finding. What are folks views on the need to address endangerment for methane generally and from this sector in particular before proceeding with regulation?

6. What about 111(d)? EPA has said that it has no plans to regulate existing sources at this time. What are the panels views on that statement? Would EPA have flexibility not to do so in light of the approach taken in the CPP

7. What would the practical implications if EPA did do an existing source guideline? How would states manage that and how would that interface with existing state regulations?

8. In terms of transmission/distribution, I've heard it said that EPA cannot justify a VOC standard under the NSPS test so is direct regulation of methane

necessary?

Best regards,

SHANNON S. BROOME
Partner
Katten Muchin Rosenman LLP
San Francisco Bay Area: 1999 Harrison Street, Suite 700 / Oakland, CA 94612-3572

p / (415) 293-5818 f / (415) 704-3151 c / (510) 816-1710

(Please note new SF direct dial number)

Washington DC: 2900 K Street NW, North Tower - Suite 200 / Washington, DC 20007-5118
p / (202) 625-3715 f / (202) 295-1125
shannon.broome@kattenlaw.com / www.kattenlaw.com

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-----Original Appointment-----
From: Broome, Shannon S.
Sent: Tuesday, May 26, 2015 10:44 AM
To: Broome, Shannon S.; David Doniger; gretchen.kern@pxd.com; gunning.paul@epa.gov; hargrove.anne@epa.gov; lreiser@nrdc.org
Subject: Preparation for Methane Panel Conference Call
When: Friday, May 29, 2015 2:00 PM-2:30 PM (UTC-05:00) Eastern Time (US & Canada).
Where: 1-866-200-9051 code 276579#

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========== NOTIFICATION: Katten Muchin Rosenman LLP is an Illinois limited liability partnership that has elected to be governed by the Illinois Uniform Partnership Act (1997).
==========

<O&G inventory table.pptx>

To: Staudt, Amanda[AStaudt@nas.edu]; Thomas, Katherine C[KCThomas@nas.edu]
Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]
From: Gunning, Paul
Sent: Tue 7/28/2015 4:34:51 PM
Subject: RE: Updated methane emissions prospectus for Wed meeting

Sounds great Amanda. Thanks again for coming over last week.

Paul

From: Staudt, Amanda [mailto:AStaudt@nas.edu]
Sent: Friday, July 24, 2015 5:49 PM
To: Gunning, Paul; Thomas, Katherine C
Subject: RE: Updated methane emissions prospectus for Wed meeting

Dear Paul,

Thanks so much for the meeting earlier this week. The input was very helpful! It would be great if Melissa could send along her written notes when she has a chance.

In terms of next steps, we will work on revising the prospectus over the next week or so, and then share a revised version for you to review again. Our plan is to get it to you the week of August 3rd. Hopefully by then we'll be getting pretty close, but we can continue to iterate as needed. Once we are in agreement, we will submit the project for Academies approval.

Have a nice weekend,

Amanda

From: Gunning, Paul [mailto:Gunning.Paul@epa.gov]

Sent: Tuesday, July 21, 2015 10:18 AM
To: Thomas, Katherine C
Cc: Staudt, Amanda
Subject: RE: Updated methane emissions prospectus for Wed meeting

Thanks Katie. See you tomorrow.

Paul

From: Thomas, Katherine C [mailto:KCThomas@nas.edu]
Sent: Monday, July 20, 2015 4:44 PM
To: Gunning, Paul
Cc: Staudt, Amanda
Subject: Updated methane emissions prospectus for Wed meeting

Dear Paul,

Amanda and I are looking forward to meeting with you Wednesday morning to discuss a potential Academies study on methane emissions monitoring and inventories. I am attaching an updated version of the prospectus.

Many thanks,

Katie

Katie Thomas
Program Officer

Board on Atmospheric Sciences and Climate
The National Academies of Sciences, Engineering, and Medicine
500 Fifth Street NW
Washington, DC 20001
202-334-3860

kcthomas@nas.edu

The National Academies of
SCIENCES · ENGINEERING · MEDICINE

To: Ragnauth, Shaun[Ragnauth.Shaun@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]
Cc: Franklin, Pamela[Franklin.Pamela@epa.gov]; Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]; Fawcett, Allen[Fawcett.Allen@epa.gov]
From: Gunning, Paul
Sent: Wed 4/29/2015 4:15:15 PM
Subject: FW: Late QER edit: please cut two Ch. 7 sentences
Appendix B_Natural Gas Sector DOE.docx

Guys please see the email below. It looks like this is one of the QER docs that has not been released yet. There is a lot in here on methane emissions and mitigation. Please let me know if we have reviewed this already (especially the MAC curve on p.50 – are these our numbers or some new DOE estimate?) and are OK with everything. Thanks

From: Roberts, Martha
Sent: Wednesday, April 29, 2015 9:59 AM
To: Ketcham-Colwill, Jim; Moss, Jacob; Gunning, Paul; DeMocker, Jim
Cc: Goffman, Joseph
Subject: RE: Late QER edit: please cut two Ch. 7 sentences

Thanks all. Attaching the document referenced by Candace – she asked if Paul or Joe, either of you had reviewed the marginal abatement curve chart in the document (figure 3-27). Don't know what spurred her question, unfortunately.

From: Ketcham-Colwill, Jim
Sent: Wednesday, April 29, 2015 9:52 AM
To: Moss, Jacob; Gunning, Paul; DeMocker, Jim
Cc: Goffman, Joseph; Roberts, Martha
Subject: Fwd: Late QER edit: please cut two Ch. 7 sentences

Paul/Jacob/Jim,

Please see Martha's question below about the marginal abatement cost curve and Figure 3-27 and reply asap. I am on leave on NC and just saw this. (I cannot see the content.). Joe, I am copying you as well because you are mentioned in connection with the question.

Jim

Sent from my iPhone

Begin forwarded message:

From: "Roberts, Martha" <Roberts.Martha@epa.gov>
To: "Ketcham-Colwill, Jim" <Ketcham-Colwill.Jim@epa.gov>
Subject: FW: Late QER edit: please cut two Ch. 7 sentences

Hi Jim,

Wanted to check in on Candace's somewhat oblique question, below. It appears from the attachment that the Appendices are still under review/editing (?), so may be worthwhile to get back to her on her question in case it changes the contents of the document.

Thanks so much,

Martha

From: Roberts, Martha
Sent: Tuesday, April 28, 2015 8:06 AM
To: Ketcham-Colwill, Jim
Subject: FW: Late QER edit: please cut two Ch. 7 sentences

Hi Jim,

Do you know the answer to Candace's question, below? I believe she is talking about the marginal abatement cost curve, Figure 3-27. Unfortunately I don't have any additional context to offer for her question.

Thanks!

Martha

From: Vahlsing, Candace Ex. 6 - Personal Privacy
Sent: Tuesday, April 28, 2015 12:21 AM
To: Roberts, Martha
Subject: RE: Late QER edit: please cut two Ch. 7 sentences

Thanks. Do you know if Goffman or Paul Gunning has seen the section on MAC curves in this appendix?

From: Roberts, Martha [mailto:Roberts.Martha@epa.gov]
Sent: Friday, April 17, 2015 9:52 PM
To: Vahlsing, Candace

Subject: Re: Late QER edit: please cut two Ch. 7 sentences

Thanks Candace, appreciate your following up and making sure those two sentences will not be in the final version. Hope you have a good weekend.

Martha

On Apr 17, 2015, at 8:02 PM, Vahlsing, Candace

Ex. 6 - Personal Privacy

wrote:

Hi Martha,

Ex. 5 - Deliberative Process

From: Roberts, Martha [mailto:Roberts.Martha@epa.gov]
Sent: Wednesday, April 08, 2015 7:14 PM
To: Vahlsing, Candace
Subject: RE: Late QER edit: please cut two Ch. 7 sentences

Great, thanks very much for the clarification.

From: Vahlsing, Candace Ex. 6 - Personal Privacy
Sent: Wednesday, April 08, 2015 7:13 PM
To: Roberts, Martha
Subject: RE: Late QER edit: please cut two Ch. 7 sentences

Hi Martha,

We deleted this entire section. Please let me know if you have any additional concerns.

Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

From: Roberts, Martha [mailto:Roberts.Martha@epa.gov]
Sent: Wednesday, April 08, 2015 7:01 PM
To: Vahlsing, Candace
Subject: FW: Late QER edit: please cut two Ch. 7 sentences

Dear Candace,

Ex. 5 - Deliberative Process

Thanks very much,

Martha
From: Roberts, Martha
Sent: Thursday, March 19, 2015 11:54 AM
To: 'Vahlsing, Candace'
Subject: Late QER edit: please cut two Ch. 7 sentences

Dear Candace,

Ex. 5 - Deliberative Process

has concurred with this edit. Feel free to give me a call if you would like to discuss.

Thank you,

Martha

Martha Roberts
Counsel, Office of Policy
Environmental Protection Agency
Office: 202-564-2286
Cell: 202-380-6677

<Appendix B_Natural Gas Sector DOE.docx>

To: Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]
Cc: Weitz, Melissa[Weitz.Melissa@epa.gov]; Bylin, Carey[Bylin.Carey@epa.gov]
From: McKittrick, Alexis
Sent: Tue 7/7/2015 2:01:47 PM
Subject: FW: INGAA invitation to AA McCabe for July 9th
INGAA CCD interaction background CCD 7 7 5 mw cb AM.docx

FYI for you two - Attached is where we ended up on the INGAA backgrounder for Janet.

From: McKittrick, Alexis
Sent: Tuesday, July 07, 2015 10:00 AM
To: Bylin, Carey; Weitz, Melissa; Kocchi, Suzanne
Cc: DeLuca, Isabel
Subject: RE: INGAA invitation to AA McCabe for July 9th

Plus GHGRP language. Let us know if you all need anything else for Janet's talk with them.

Alexis

From: Bylin, Carey
Sent: Tuesday, July 07, 2015 9:57 AM
To: Weitz, Melissa; Kocchi, Suzanne; McKittrick, Alexis
Cc: DeLuca, Isabel
Subject: RE: INGAA invitation to AA McCabe for July 9th

I added a response relative to their DI&M proposal.

Ms. Carey Bylin

International Programs Leader, Oil and Gas

Natural Gas STAR Program

Global Methane Initiative

U.S. Environmental Protection Agency

Phone: +1-202-343-9669

Visiting Address & Private Deliveries (courier, FedEx etc.)

1201 Constitution Ave NW, Room Number 4353 UU, Washington DC 20004

U.S. Mail Address:

Mail Code 6207M, 1200 Pennsylvania Ave NW, Washington DC 20460

From: Weitz, Melissa
Sent: Tuesday, July 07, 2015 9:37 AM
To: Kocchi, Suzanne; McKittrick, Alexis; Bylin, Carey
Cc: DeLuca, Isabel
Subject: RE: INGAA invitation to AA McCabe for July 9th

I added info to the inventory section.

From: Kocchi, Suzanne
Sent: Tuesday, July 07, 2015 8:38 AM
To: Weitz, Melissa; McKittrick, Alexis; Bylin, Carey
Cc: DeLuca, Isabel
Subject: FW: INGAA invitation to AA McCabe for July 9th

Importance: High

+Carey – didn't realize she wasn't on yesterday.

From: DeLuca, Isabel
Sent: Tuesday, July 07, 2015 8:36 AM
To: Weitz, Melissa; Kocchi, Suzanne
Cc: McKittrick, Alexis
Subject: RE: INGAA invitation to AA McCabe for July 9th

Melissa, thanks for the added bullet yesterday.

In the attached I've inserted a few remaining questions related to Methane Challenge, GHGRP, and Inventory. Where we indicate that INGAA is requesting something, do you think it would

Ex. 5 - Deliberative Process

Thanks,

Isabel

From: Weitz, Melissa
Sent: Monday, July 06, 2015 5:09 PM
To: Kocchi, Suzanne
Cc: DeLuca, Isabel; McKittrick, Alexis
Subject: RE: INGAA invitation to AA McCabe for July 9th

Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

From: Kocchi, Suzanne
Sent: Monday, July 06, 2015 5:02 PM
To: Weitz, Melissa
Cc: DeLuca, Isabel; McKittrick, Alexis
Subject: FW: INGAA invitation to AA McCabe for July 9th
Importance: High

Ex. 5 - Deliberative Process

Thanks!

From: DeLuca, Isabel
Sent: Monday, July 06, 2015 4:55 PM
To: Gunning, Paul; Kocchi, Suzanne
Subject: FW: INGAA invitation to AA McCabe for July 9th

Hi Paul,

Apologies—I should've cc'd you on the note below. We've been contributing to some talking

points for Janet for a presentation she'll be giving to the INGAA Board of Directors on Thurs at 9:30. (It's a little awkward because one of their primary interests is the new voluntary program and we don't know if Methane Challenge will be out by that point.)

If you have comments/edits, we can work them in before they go in Janet's book tomorrow evening. Carey, Suzie W, and Mark have weighed in already.

Thanks!
Isabel

From: DeLuca, Isabel
Sent: Monday, July 06, 2015 4:32 PM
To: Dennis, Allison; Noonan, Jenny; Davis, Alison; Cortelyou-Lee, Jan
Cc: Krieger, Jackie; Lemon, Mollie; Friedman, Kristina; Millett, John
Subject: RE: INGAA invitation to AA McCabe for July 9th

Hi Allison,

Apologies, but we added another bullet to the talkers (attached) to reflect a bit more interaction we've had with INGAA regarding Natural Gas STAR Methane Challenge.

Also attached is the background doc we discussed, with more detail on recent interactions we've had with INGAA related to the Methane Challenge and Gas STAR. I think we want to polish this a bit—if so I'll send you a revised version shortly.

Let me know if you have questions or comments.

Best,

Isabel

From: DeLuca, Isabel
Sent: Monday, July 06, 2015 3:00 PM
To: Dennis, Allison; Noonan, Jenny; Davis, Alison; Cortelyou-Lee, Jan
Cc: Krieger, Jackie; Lemon, Mollie; Friedman, Kristina; Millett, John
Subject: RE: INGAA invitation to AA McCabe for July 9th

Hi Allison,

Here are CCD's edits to the talkers (added bullets on Methane Challenge and GHGRP). You'll see I've included two versions of the Methane Challenge bullets – one set if we've posted the proposal by Thursday, the other if not. We're also pulling together some background talkers that describe our interaction with INGAA companies re: Methane Challenge. Might be good for her to have that background in case she gets questions.

Please let me know if you have any questions.

Isabel

From: Dennis, Allison
Sent: Monday, July 06, 2015 10:27 AM
To: Noonan, Jenny; DeLuca, Isabel; Davis, Alison; Cortelyou-Lee, Jan
Cc: Krieger, Jackie; Lemon, Mollie; Friedman, Kristina; Millett, John
Subject: RE: INGAA invitation to AA McCabe for July 9th

+ Jan for awareness

From: Dennis, Allison
Sent: Wednesday, July 01, 2015 1:28 PM
To: Noonan, Jenny; DeLuca, Isabel; Davis, Alison
Cc: Krieger, Jackie; Lemon, Mollie; Friedman, Kristina; Millett, John
Subject: RE: INGAA invitation to AA McCabe for July 9th

Thank you Alison for that background info and slides. I used those slides for the attached first draft of Janet's talkers. Can you all take a look and send me feedback **by next Monday COB**? I kinda hope our methane challenge will be out in time for this mtg (next Thursday at 9:30) because that would be of high interest to this group.

OAQPS- I put in some talkers about PM Implementation and Ozone but if you don't think this will come up- feel free to delete or I can just mark it as "background".

Happy to answer any questions and provide more information. /Allison

From: Dennis, Allison
Sent: Monday, June 29, 2015 6:59 PM
To: Noonan, Jenny; DeLuca, Isabel; Davis, Alison
Cc: Krieger, Jackie; Lemon, Mollie; Friedman, Kristina; Millett, John
Subject: RE: INGAA invitation to AA McCabe for July 9th

And, here's the completed event form! 30 minutes of talkers followed by 30 minutes of Q&A.

What they want to hear about: (mainly methane) INGAA would like Ms. McCabe to address the anticipated voluntary approaches for existing sources in the transmission and storage segment of the natural gas industry as well as to speak about the upcoming proposed rule to regulate methane at new sources. INGAA requests that enough time be provided for the attendees to ask questions. The participants do not need basic primer on CAA, GHGs, Supreme Court decision etc. They will be familiar with the background and are far more interested in what the EPA is envisioning for the pipeline sector. INGAA represents interstate natural gas transmission pipelines, and not producers or distributors of natural gas. The group will be interested in the options for Best Management Practices (BMPs) and percentage reduction approaches.

I can check with Janet to see how she wants her prep materials (formal TPs vs. backgrounders on various topics).

Still interested in what you all think as far as topics to cover during this meeting (and hot button issues she should be aware of). /Allison

From: Dennis, Allison
Sent: Monday, June 29, 2015 5:44 PM
To: Noonan, Jenny; DeLuca, Isabel; Davis, Alison
Cc: Krieger, Jackie; Lemon, Mollie; Friedman, Kristina; Millett, John
Subject: FW: INGAA invitation to AA McCabe for July 9th

Hi all,

Janet will be speaking at the INGAA board meeting Thursday, July 9th, from 9:30- 10:30 am. They are due to provide me with a completed event form soon (see original invite attached), which will give me a better sense of what they want to hear about and how much time to allot for Q&A but in an effort to get the prep work started…... I wanted to get a sense from ya'll of topics that she should cover for this meeting.

I'm thinking she would provide a general update on our office's priority actions:

CAP:

•□□□□□□□□ A brief mention of the CPP

•□□□□□□□□ Oil and Gas:

- NSPS for Oil and Gas , CTGs
- Methane Challenge Launch
- GHGRP Reporting Rule

Non-CAP Actions:

PM: It looks like they care about our PM NAAQS: http://www.ingaa.org/Filings/23952.aspx

Ozone: http://www.ingaa.org/Filings/11520/24087.aspx

Anything else?

From: Theresa Pugh [mailto:tpugh@ingaa.org]
Sent: Monday, June 29, 2015 11:54 AM
To: Drinkard, Andrea; Dennis, Allison
Cc: Nichole Willison; Dewey, Amy; Browne, Cynthia; Atkinson, Emily
Subject: INGAA invitation to AA McCabe for July 9th

Good morning, Andrea and Allison:

We have confirmed Ms. McCabe's talk on July 9th. It is located at the Westin Georgetown at 2350 M Street. (The details will be on the form that you asked us to fill out).

Might I inquire if

(a) Ms. McCabe will have any other staff people with her at the July 9th meeting and, if so, may I get their names/titles?

(b) Would she be comfortable with a lavalier microphone to ensure that everyone can hear her clearly? It is not always easy to predict the acoustics of meeting rooms in advance. I tend to lean toward mics, especially for women, since sometimes women's voices don't carry as well in elongated rooms or if there are pillars.

Thank you.

Theresa

Theresa Pugh

Vice President

Environment, Health & Construction Policy

Interstate Natural Gas Association of America (INGAA)

20 F Street, NW

Suite 450

Washington, D. C. 20001

tpugh@ingaa.org

202-216-5955

From: Drinkard, Andrea [mailto:Drinkard.Andrea@epa.gov]
Sent: Friday, June 19, 2015 3:08 PM
To: Theresa Pugh; Dennis, Allison
Cc: Nichole Willison; Dewey, Amy; Browne, Cynthia; Atkinson, Emily
Subject: RE: INGAA invitation to AA McCabe

Hi Theresa,

Thank you so much for the invitation and it's good to hear from you. Your email is very timely as we just had our scheduling meeting today. I spoke with Janet and she would be delighted to accept your invitation to come to your board meeting. After looking at the calendar, we think we can make 9:30-10:30AM work on July 9th. Would that work for your agenda?

I'm also attaching our event form to this email. If you could fill it out and get it back to us at your earliest convenience that will help us prep for the event.

On a logistical note, I will be heading out on maternity leave some time in the next few weeks. In my absence, Allison Dennis (cced on your note and here) will be the point of contact.

Thanks again for the invite and looking forward to it!

-Andrea-

Andrea Drinkard

Deputy Communications Director

EPA Office of Air and Radiation

202.564.1601

From: Theresa Pugh [mailto:tpugh@ingaa.org]
Sent: Friday, June 19, 2015 1:20 PM
To: Drinkard, Andrea; Dennis, Allison
Cc: Nichole Willison; Dewey, Amy
Subject: INGAA invitation to AA McCabe

Dear Ms. Drinkard and Ms. Dennis:

Good afternoon. INGAA is writing to invite Janet to speak at the INGAA July 9 Board of Directors meeting as described in the letter. As described in the letter, INGAA represents 200,000 miles of U. S. interstate natural gas pipelines.

Please note that if you respond you should make sure you are using the INGAA domain address not my prior e mail address that was used often on behalf of another industry. I am copying Ms.

Dewey of the Administrator's office as she is familiar with our organization.

Thank you very much.

Theresa

Theresa Pugh

Vice President

Environment, Health & Construction Policy

Interstate Natural Gas Association of America (INGAA)

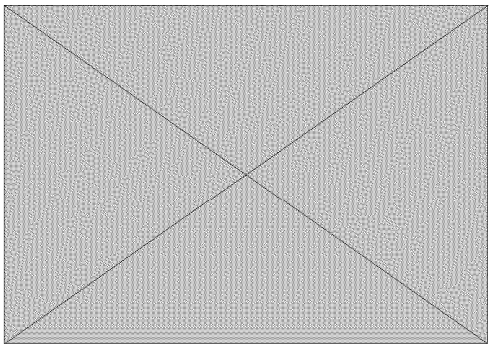
20 F Street, NW

Suite 450

Washington, DC 20001

202-216-5955

tpugh@ingaa.org



To: Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Weitz, Melissa[Weitz.Melissa@epa.gov]; Bylin, Carey[Bylin.Carey@epa.gov]
Cc: Franklin, Pamela[Franklin.Pamela@epa.gov]
From: Gunning, Paul
Sent: Fri 4/24/2015 1:45:07 PM
Subject: FW: Liquids Unloading Analysis
Cost Effectiveness of Flares for Liquids Unloading 20150422.pdf

FYI.,..

From: Peter Zalzal [mailto:pzalzal@edf.org]
Sent: Thursday, April 23, 2015 5:41 PM
To: Moore, Bruce; Gunning, Paul
Cc: Tomas Carbonell
Subject: Liquids Unloading Analysis

Dear Mr. Moore and Mr. Gunning:

We have attached an analysis of liquids unloading emissions from the 107 wells measured in a recent study by Allen *et al.* This preliminary analysis examines the cost effectiveness of deploying flares (both mobile and stationary) to reduce emissions at these wells and assesses their effectiveness at several performance-based thresholds. Our results suggest that a requirement to mitigate liquids unloading emissions from wells that emit above certain annual thresholds would be cost-effective and yield significant emission reductions.

For instance, In the Allen study, wells that vented at least 250 Mcf per year of methane represented approximately 16% of the projected well population, but accounted for 95% of the total measured emissions in the study. If flares with a combustion efficiency of 98% were deployed at this subset of wells, total measured emissions from all wells in the dataset would be reduced by 93%. The average cost-effectiveness of these

reductions would be $140-$260 per ton of methane reduced.

Best wishes,

Peter Zalzal

Peter Zalzal
Senior Attorney

U.S. Climate and Air

Environmental Defense Fund
2060 Broadway, Suite 300
Boulder, CO 80302
T 303 447 7214
C 303 946 0907
pzalzal@edf.org

edf.org

This e-mail and any attachments may contain confidential and privileged information. If you are not the intended recipient, please notify the sender immediately by return e-mail, delete this e-mail and destroy any copies. Any dissemination or use of this information by a person other than the intended recipient is unauthorized and may be illegal.

To: Gordon, Jessica M[Gordon.Jessica@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]; Franklin, Pamela[Franklin.Pamela@epa.gov]; Gunning, Paul[Gunning.Paul@epa.gov]
Cc: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Banks, Julius[Banks.Julius@epa.gov]
From: Weitz, Melissa
Sent: Wed 5/11/2016 9:00:37 PM
Subject: RE: flash review: NALS Methane Collaboration

With the edit to ¢ **Ex. 5 - Deliberative Process** this seems fine to me.

Others?

From: Gordon, Jessica M
Sent: Wednesday, May 11, 2016 4:54 PM
To: Irving, Bill <Irving.Bill@epa.gov>; Franklin, Pamela <Franklin.Pamela@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>
Cc: Weitz, Melissa <Weitz.Melissa@epa.gov>; DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>; Banks, Julius <Banks.Julius@epa.gov>
Subject: RE: flash review: NALS Methane Collaboration

Last call for comments/edits on this draft. **Ex. 5 - Deliberative Process**
Ex. 5 - Deliberative Process ? Thanks.

Jessica M. Gordon
International Climate Advisor

Office of Air and Radiation/Immediate Office

(202) 343-9444
gordon.jessica@epa.gov

From: Gordon, Jessica M
Sent: Wednesday, May 11, 2016 2:15 PM
To: Irving, Bill <Irving.Bill@epa.gov>; Franklin, Pamela <Franklin.Pamela@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>
Cc: Weitz, Melissa <Weitz.Melissa@epa.gov>; DeFigueiredo, Mark

<DeFigueiredo.Mark@epa.gov>; Banks, Julius <Banks.Julius@epa.gov>
Subject: flash review: NALS Methane Collaboration

The deadline for feedback on this (and the whole methane text, pasted below) is 5 pm today, so please let me know whether or not it looks ok. (I'm already reiterating our comments about the problems with "collaborate" rather than "information-sharing" under Data Collection.

Thanks!

Jessica

Current NALS methane text:

Ex. 5 - Deliberative Process

* Work Collaboratively on Federal Measures to Reduce Methane Emissions: Building on existing collaborations, the three parties decide to work together on programs, policies, and strategies, and to exchange information, practices and experiences regarding reducing emissions in the oil and gas sector to improve environmental outcomes. Canada and the United States commit to finalizing and implementing their respective federal regulations and other measures as

Ex. 5 - Deliberative Process

Jessica M. Gordon
International Climate Advisor

Office of Air and Radiation/Immediate Office

(202) 343-9444
gordon.jessica@epa.gov

From: Gordon, Jessica M
Sent: Tuesday, May 10, 2016 3:33 PM
To: Irving, Bill <Irving.Bill@epa.gov>; Franklin, Pamela <Franklin.Pamela@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>
Cc: Weitz, Melissa <Weitz.Melissa@epa.gov>; DeFigueiredo, Mark

<DeFigueiredo.Mark@epa.gov>; Banks, Julius <Banks.Julius@epa.gov>
Subject: RE: NALS Methane Collaboration

Bill and all,

Ex. 5 - Deliberative Process

Thanks,

Jessica

Jessica M. Gordon
International Climate Advisor

Office of Air and Radiation/Immediate Office

(202) 343-9444
gordon.jessica@epa.gov

From: Irving, Bill
Sent: Wednesday, April 20, 2016 1:29 PM
To: Gordon, Jessica M <Gordon.Jessica@epa.gov>; Franklin, Pamela <Franklin.Pamela@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>
Cc: Weitz, Melissa <Weitz.Melissa@epa.gov>; DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>; Banks, Julius <Banks.Julius@epa.gov>
Subject: RE: NALS Methane Collaboration

Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

From: Gordon, Jessica M
Sent: Wednesday, April 20, 2016 8:05 AM
To: Franklin, Pamela <Franklin.Pamela@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; Irving, Bill <Irving.Bill@epa.gov>
Subject: Fwd: NALS Methane Collaboration

+ Bill

Sent from my iPhone

Begin forwarded message:

From: "Vahlsing, Candace M. EOP/WHO" <Candace_M_Vahlsing@who.eop.gov>
Date: April 20, 2016 at 12:22:06 AM EDT
To: "Gant, Paula" <Paula.Gant@Hq.Doe.Gov>, "Florini, Karen L" <FloriniKL@state.gov>, "ryan_close@ios.doi.gov" <ryan_close@ios.doi.gov>, "Cerqueira, Julie" <CerqueiraJ@state.gov>, Paul Gunning <Gunning.Paul@epa.gov>, "Franklin, Pamela" <Franklin.Pamela@epa.gov>, "Gordon, Jessica M" <Gordon.Jessica@epa.gov>
Subject: NALS Methane Collaboration

Hi team,

We're been asked to submit draft methane ideas for the NALS summit. The idea with the entire summit is to build on the collaboration with had with Canada. I started an initial draft based on conversations with a few of you. We have a deadline of the end of the day tomorrow to submit the language, but its only a draft. Please give this a look and let me know if you have any edits before 5 am.

Feel free to + in additional members of your team.

Thank you.

Methane

Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

The U.S., Canada, and Mexico will report annually on progress achieved through the [TBD mechanism].

To: Gunning, Paul[Gunning.Paul@epa.gov]
Cc: Irving, Bill[Irving.Bill@epa.gov]; Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]
From: Weitz, Melissa
Sent: Thur 2/2/2017 10:18:06 PM
Subject: FW: Briefing on natural gas CH4 emission synthesis

NETL developed a synthesis of the EDF study data, and published an estimate of national CH4 from natural gas systems based on that data today.

They are holding a public webinar on it next week.

Ex. 5 - Deliberative Process

Let me know if you'd like more information.

From: Littlefield, James A. (CONTR) [mailto:James.Littlefield@NETL.DOE.GOV]
Sent: Thursday, February 02, 2017 3:23 PM
To: Littlefield, James A. (CONTR) <James.Littlefield@NETL.DOE.GOV>
Subject: Briefing on natural gas CH4 emission synthesis

Dear Colleague –

On behalf of Tim Skone and the LCA team at NETL, I'd like to invite you to attend a briefing on Tuesday, February 7th, from 1 to 2 PM EST. We will be providing an overview of our synthesis of natural gas methane emissions measured by EDF's recent ground-level campaigns. This study has been accepted for publication in the *Journal of Cleaner Production.* The study uses the latest data to develop national values for the CH4 emission rate from the natural gas supply chain, from production through delivery. It also prioritizes top emission reduction opportunities and makes recommendations for future research. This work is the outcome of collaboration between NETL and EDF.

Details on attending the briefing are below (we are using WebEx for visuals and phone for audio). Please feel free to forward the invitation to anyone else you think might be interested.

Sincerely,

James Littlefield

NETL LCA Team

(412) 386-7560

Tuesday, February 7, 2017

1:00-2:00pm EST

Meeting number: 741 013 502

Meeting password: Meeting password: SjAJ7ip*

Join meeting:
https://mmancusa.webex.com/mmancusa/j.php?MTID=meba89a36f007906136b261c2f6b9df01

Join by phone Ex. 5 - Deliberative Process Passcode: Ex. 5 - Deliberative Process

To: Gunning, Paul[Gunning.Paul@epa.gov]; Fawcett, Allen[Fawcett.Allen@epa.gov]; Alsalam, Jameel[Alsalam.Jameel@epa.gov]; DeLuca, Isabel[DeLuca.Isabel@epa.gov]; Gordon, Jessica M[Gordon.Jessica@epa.gov]
Cc: Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]
From: Weitz, Melissa
Sent: Mon 6/27/2016 5:35:43 PM
Subject: RE: NALS Methane Q and A

Sure-we can get you a response this afternoon.

From: Gunning, Paul
Sent: Monday, June 27, 2016 12:51 PM
To: Fawcett, Allen <Fawcett.Allen@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>; Alsalam, Jameel <Alsalam.Jameel@epa.gov>; DeLuca, Isabel <DeLuca.Isabel@epa.gov>; Gordon, Jessica M <Gordon.Jessica@epa.gov>
Cc: Kocchi, Suzanne <Kocchi.Suzanne@epa.gov>
Subject: FW: NALS Methane Q and A

Ex. 5 - Deliberative Process

Melissa – can you please work with Isabel to suggest a response.

Thanks

Paul

From: Vahlsing, Candace M. EOP/WHO **Ex. 6 - Personal Privacy**
Sent: Monday, June 27, 2016 12:24 PM
To: Gordon, Jessica M <Gordon.Jessica@epa.gov>; Goffman, Joseph <Goffman.Joseph@epa.gov>; McCabe, Janet <McCabe.Janet@epa.gov>; Gunning, Paul

<Gunning.Paul@epa.gov>
Cc: Utech, Dan G. EOP/WHO < Ex. 6 - Personal Privacy ; Duke, Rick D. EOP/CEQ
Ex. 6 - Personal Privacy
Subject: NALS Methane Q and A

Hi Team,

Ex. 5 - Deliberative Process

I also wanted to check with you on the a topline number. Is this accurate based on your understanding?

Ex. 5 - Deliberative Process

Happy to answer any questions.

Thank you very much

From: Weitz, Melissa
Location: DCRoomWJCE5140OAPTB/DC-OAR-OAP
Importance: Normal
Subject: Tentative: Methane & Emissions Discussion w/LPP Combustion / Call-in: Ex. 5 - Deliberative Process
Code: Ex. 5 - Deliberative Process
Start Date/Time: Thur 6/9/2016 3:45:00 PM
End Date/Time: Thur 6/9/2016 4:45:00 PM

To: Harrison, Matt[matt.harrison@aecom.com]
From: Weitz, Melissa
Sent: Wed 11/16/2016 7:27:58 PM
Subject: RE: You Gridded Map

Hi Matt,

The paper actually just came out today-link below. I would use figures from the paper as opposed to anything I had in previous presentations as they may have used an earlier draft of the map. We have a few of the images posted on our website as well.

Melissa

http://pubs.acs.org/doi/full/10.1021/acs.est.6b02878

https://www.epa.gov/ghgemissions/gridded-2012-methane-emissions

From: Harrison, Matt [mailto:matt.harrison@aecom.com]
Sent: Wednesday, November 16, 2016 9:54 AM
To: Weitz, Melissa <Weitz.Melissa@epa.gov>
Subject: You Gridded Map
Importance: High

Melissa,

Can you sent me your slide deck or your paper on the gridded GHG emissions from the GHGI?

Thank you,

Matt

Matthew Harrison, P.E.

Vice President

AECOM – Design Consulting Services, Environmental

matt.harrison@AECOM.com

512-694-0572

To: McKittrick, Alexis MW[amckittr@ida.org]; Clavin, Christopher T[cclavin@ida.org]
From: Weitz, Melissa
Sent: Thur 1/12/2017 11:10:45 PM
Subject: RE: Behind the meter emissions

I'll try to look into this tomorrow but I may not be able to. My recollection is that the uncombusted natural gas #s take into account that some fraction of the gas leaks.

Could you address this by saying that it includes uncombusted methane in the fossil fuel combustion calculations, but may not include all natural gas methane that could be emitted behind the meter? I think that covers both interpretations and makes the point that certain sources may not be fully included?

From: McKittrick, Alexis MW [mailto:amckittr@ida.org]
Sent: Thursday, January 12, 2017 5:15 PM
To: Clavin, Christopher T <cclavin@ida.org>; Weitz, Melissa <Weitz.Melissa@epa.gov>
Subject: RE: Behind the meter emissions

Hi Melissa,

I'm just following up on Chris' note below, since he is off-site today and we are planning to finalize our report for DOE tomorrow. Can you confirm whether or not behind the meter natural gas leaks are covered in the GHGI? As Chris notes below, we recognize the point about methane from uncombusted fossil fuel that is behind the meter being covered elsewhere in the GHGI, but we don't interpret this to include any natural gas leaks. I hope that makes sense.

Thanks for your help,

Alexis

From: Clavin, Christopher T
Sent: Wednesday, January 11, 2017 5:40 PM
To: Weitz, Melissa
Cc: McKittrick, Alexis MW

Subject: Behind the meter emissions

Hi Melissa,

Thanks for taking the time to chat with James last week. Per your feedback and his, I'm going back and double checking some of our discussion related to GHGI underlying assumptions.

One comment that James passed along to me said that the GHGI includes behind the meter CH4 emissions in the fossil fuel combustion section of the inventory. Can you help me make sure I correctly understand, and update our report with the correct information?

First, I'm making edits to the report to ensure the readers know that meter CH4 emissions ARE included in the inventory, and based on EIA data for activity data and the EFs are based on updates cited in the 2016 EPA NG distribution white paper (Annex Table A-138).

Now for behind the meter emissions, from looking through annex 3.1, the CH4 EF for stationary combustion (table A-87) does provide natural gas combustion CH4 emissions factors, which from the earlier discussion in the annex (step 2. Determine the amount of CH4 and N2O emitted), are based upon the 2006 IPCC guidelines. After briefly reviewing the 2006 IPCC guidelines, I'm still unclear whether behind-the-meter emissions that are not the result of uncombusted natural gas in the stationary combustion category, but are a result of leaks within homes, commercial and industrial facilities. Are these leaks accounted for in this stationary combustion EF?

Can you help me out? I feel like at some point I lost the scent and got off the trail that would lead me to the answer…

Thanks.

Chris

Christopher Clavin

Institute for Defense Analyses
Science & Technology Policy Institute
1899 Pennsylvania Avenue NW, Suite 520
Washington, DC 20006
202-419-5416, cclavin@ida.org

To: Gunning, Paul[Gunning.Paul@epa.gov]
From: Weitz, Melissa
Sent: Tue 12/6/2016 6:31:37 PM
Subject: RE: MethaneTransition_SPPD_edits 12-6-2016.docx
MethaneTransition_SPPD_edits 12-6-2016 ccd.docx

I've added CCD edits to David's version.

From: Gunning, Paul
Sent: Tuesday, December 06, 2016 1:22 PM
To: Cozzie, David <Cozzie.David@epa.gov>
Cc: Lassiter, Penny <Lassiter.Penny@epa.gov>; Tsirigotis, Peter <Tsirigotis.Peter@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>; Kocchi, Suzanne <Kocchi.Suzanne@epa.gov>
Subject: RE: MethaneTransition_SPPD_edits 12-6-2016.docx

Thanks David!!

From: Cozzie, David
Sent: Tuesday, December 06, 2016 1:00 PM
To: Gunning, Paul <Gunning.Paul@epa.gov>
Cc: Lassiter, Penny <Lassiter.Penny@epa.gov>; Tsirigotis, Peter <Tsirigotis.Peter@epa.gov>; Cozzie, David <Cozzie.David@epa.gov>
Subject: MethaneTransition_SPPD_edits 12-6-2016.docx

Paul,

Attached are edits from SPPD on the transition paper for Oil and Gas ICR.

David

To: Gunning, Paul[Gunning.Paul@epa.gov]
Cc: Irving, Bill[Irving.Bill@epa.gov]
From: Weitz, Melissa
Sent: Mon 11/6/2017 10:17:09 PM
Subject: FW: COP Background Notes
COP Bilateral Background.docx
EPA MOE Joint Statement 2016.pdf
EPA MOE Joint Statement 2015.pdf
Japan Background Paper for COP23 v2.docx

Any edits to the bilateral materials?

I'm not sure what the process is for getting these to Mandy and Brittany. Let me know if you have been coordinating this, or if I should work with Henry to figure it out.

Thanks!

Melissa

From: Ferland, Henry
Sent: Monday, November 06, 2017 5:08 PM
To: Kasman, Mark <Kasman.Mark@epa.gov>; Shoaff, John <Shoaff.John@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; Irving, Bill <Irving.Bill@epa.gov>; Krieger, Jackie <Krieger.Jackie@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>
Cc: Dieu, Martin <Dieu.Martin@epa.gov>; Almodovar, Lisa <Almodovar.Lisa@epa.gov>; Hill-Macon, Cam <Hill-Macon.Cam@epa.gov>; Doroski, Brenda <Doroski.Brenda@epa.gov>; Troche, Luis <Troche.Luis@epa.gov>; Finman, Hodayah <Finman.Hodayah@epa.gov>
Subject: RE: COP Background Notes

Hey Mark:

Super helpful…After reading through these – think you captured air equities nicely (E.G., workshops in China, AQA -CCAC-GMI Canada etc..) and am not making any changes. Am recommending Melissa share these directly with Mandy and Brittany as-is to add to their books.

Very much appreciate the quick, excellent, and comprehensive work by OITA here!

Thx,

H

HENRY FERLAND | *INTERNATIONAL COORDINATOR*

U.S. EPA OFFICE OF AIR & RADIATION

Ferland.Henry@epa.gov | 1-202-343-9330

From: Kasman, Mark
Sent: Monday, November 06, 2017 4:47 PM
To: Ferland, Henry <Ferland.Henry@epa.gov>; Shoaff, John <Shoaff.John@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; Irving, Bill <Irving.Bill@epa.gov>; Krieger, Jackie <Krieger.Jackie@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>
Cc: Dieu, Martin <Dieu.Martin@epa.gov>; Almodovar, Lisa <Almodovar.Lisa@epa.gov>; Hill-Macon, Cam <Hill-Macon.Cam@epa.gov>; Doroski, Brenda <Doroski.Brenda@epa.gov>; Troche, Luis <Troche.Luis@epa.gov>; Finman, Hodayah <Finman.Hodayah@epa.gov>
Subject: RE: COP Background Notes

Sorry that my attachments did not make it on the loop-in. Here is another attempt.

From: Kasman, Mark
Sent: Monday, November 06, 2017 4:36 PM
To: Ferland, Henry <Ferland.Henry@epa.gov>; Shoaff, John <Shoaff.John@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>; Irving, Bill <Irving.Bill@epa.gov>; Krieger, Jackie <Krieger.Jackie@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>
Cc: Dieu, Martin <Dieu.Martin@epa.gov>; Almodovar, Lisa <Almodovar.Lisa@epa.gov>; Hill-Macon, Cam <Hill-Macon.Cam@epa.gov>; Doroski, Brenda <Doroski.Brenda@epa.gov>; Troche, Luis <Troche.Luis@epa.gov>; Finman, Hodayah <Finman.Hodayah@epa.gov>
Subject: RE: COP Background Notes

Looping in some of our other OAR colleagues….

From: Kasman, Mark
Sent: Monday, November 06, 2017 4:32 PM
To: Ferland, Henry <Ferland.Henry@epa.gov>
Cc: Dieu, Martin <Dieu.Martin@epa.gov>; Almodovar, Lisa <Almodovar.Lisa@epa.gov>; Hill-Macon, Cam <Hill-Macon.Cam@epa.gov>; Doroski, Brenda <Doroski.Brenda@epa.gov>; Troche, Luis <Troche.Luis@epa.gov>
Subject: COP Background Notes

Hi Henry,

Attached are the background notes for the COP papers you are preparing for Mandy and Brittany.

We have also included the more robust paper that was requested for Japan.

Can we have a copy of the finished product that you send up the chain?

Thanks, Mark

Mark S. Kasman

Director

Office of Regional and Bilateral Affairs

Office of International and Tribal Affairs

U.S. Environmental Protection Agency

1300 Pennsylvania Avenue, N.W.

Washington, D.C. 20460

TEL: 202-564-2024 FAX: 202-565-2412

To: Gunning, Paul[Gunning.Paul@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]
Cc: Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]
From: Weitz, Melissa
Sent: Tue 12/6/2016 5:09:14 PM
Subject: RE: methane ICR "briefing"
MethaneTransition MdF mw.docx

We provided responses/edits in the attached.

I don't know if Peter has shared the document with his group yet. I can send our mark up to them to be sure that we're all on the same page going into the meeting this afternoon.

I'll plan to bring copies of the latest clean and redline versions this afternoon.

Melissa

From: Gunning, Paul
Sent: Tuesday, December 06, 2016 8:44 AM
To: Weitz, Melissa <Weitz.Melissa@epa.gov>; DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>; Waltzer, Suzanne <Waltzer.Suzanne@epa.gov>
Cc: Kocchi, Suzanne <Kocchi.Suzanne@epa.gov>
Subject: FW: methane ICR "briefing"

Can you guys please take a look at this. We can give her any feedback we have at our meeting later today.

Thanks

Paul

From: Dunham, Sarah
Sent: Monday, December 05, 2016 4:34 PM
To: Tsirigotis, Peter <Tsirigotis.Peter@epa.gov>; Gunning, Paul <Gunning.Paul@epa.gov>
Cc: Page, Steve <Page.Steve@epa.gov>; Schmidt, Lorie <Schmidt.Lorie@epa.gov>
Subject: methane ICR "briefing"

I am attaching my internal only cheat sheet for the upcoming (likely Thursday) briefing on the methane ICR. I do not plan to hand this to anyone, nor do I plan to go through this word for word, but to help prepare for the briefing I wanted to put in one place the basics on the ICR. All of this is taken from already public info like the fact sheets. I am sorry to ask you to do any work on this, but it would be super helpful if you could confirm that I didn't say anything wrong, and there are a couple places in red where some feedback/fill in the blanks would be useful. Lorie, I think this briefing is now on your calendar as well. [and to anticipate another reaction when you look at this-- I really do not plan to get in to any of the additional background info that I have included here after the ICR stuff, but its here in case there are basic questions that come up in the broader methane context].

From: Weitz, Melissa
Location: Ex. 6 - Personal Privacy
Importance: Normal
Subject: natural gas CH4 quantification list for DOE
Start Date/Time: Wed 2/17/2016 3:30:00 PM
End Date/Time: Wed 2/17/2016 4:00:00 PM

DOE was recently given $5 million to conduct research that can be used to update the GHGI for natural gas systems (language from congressional budget request is below).

DOE has given us a list of their thoughts for projects (I'll send around soon). We need to get back to DOE with our priority list of emissions sources/research projects, on a tight time frame (by February 19). I'll take a first stab at a list (based on information we already shared with DOE and this group several months ago) and send that around before the call, and then I'd like to use this call to discuss whether any of the priorities may be duplicative with other research or data efforts, and whether there are any additional priority areas we should consider.

Congressional Budget Request FY 2016-- Emissions Quantification form Natural Gas Infrastructure
The Emissions Quantification from Natural Gas Infrastructure research subprogram will focus on better quantifying methane emissions from the natural gas value chain. The program will work with the Environmental Protection Agency to ensure that data produced is compatible with the national Greenhouse Gas Inventory. Efforts will focus on understanding regional variation and reducing uncertainty in emission estimates.

The Cost Effectiveness of Mitigating Liquids Unloading Emissions Using Flares

April 2015

This analysis examines the 107 liquids unloading wells measured by Allen et al.[1] and evaluates the cost-effectiveness of deploying flares to reduce methane and VOC emissions at those wells. Rigorous, well-designed standards for liquids unloading should directly regulate methane emissions. As set forth in the tables below, direct regulation of methane produces the lowest cost-effectiveness numbers.

Because the Allen dataset shows that most emissions come from a discrete set of wells, this memo analyzes the effectiveness of reducing emissions only at wells above various emission thresholds. Moreover, the analysis focuses on flaring technology, despite the existence of other highly cost-effective technologies, because flares can be applied at all wells. Operators should nonetheless be able to deploy other technologies, where feasible, to meet a performance standard. Because these other technologies often result in capture of natural gas that would otherwise be wasted, they could enhance cost-effectiveness beyond the numbers presented here.[2]

For this analysis, we evaluate the use of either mobile or stationary flares depending on well type, and for each, assess the cost-effectiveness of both rental and purchase.[3] The results set forth below represent a preliminary assessment of the cost-effectiveness of deploying flares above certain venting thresholds, and accordingly, rely on assumptions from existing literature concerning the cost and effectiveness of flaring technology.

Summary Results.

These preliminary results suggest that a requirement to mitigate liquids unloading emissions from wells that emit above certain annual thresholds would be cost-effective and yield significant emission reductions. In the Allen study, wells that vented at least 250 Mcf per year of methane represented approximately 16% of the projected well population, but accounted for 95% of the total measured

[1] David T. Allen et al., Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquids Unloading, 49 J. Environ. Sci. & Tech. 641 (2014), *available at* http://pubs.acs.org/doi/abs/10.1021/es504016r.

[2] For instance, IFC estimates that the cost effectiveness of deploying plunger lifts at uncontrolled wells is approximately $75/ton methane reduced.

[3] Where a producer determines other more cost-effective technologies can effectively reduce emissions, however, producers should be afforded latitude to deploy those technologies.

emissions in the study.[4] If flares with a combustion efficiency of 98% were deployed at this subset of wells, total measured emissions from all wells in the dataset would be reduced by 93%. The average cost-effectiveness of these reductions would be $140-$260 per ton of methane reduced (approximately $6-$10 per ton of CO_2-e, using a methane global warming potential of 25) and $940-$1,800 per ton of VOC reduced.[5] The distribution of emissions for the different well types is shown in Figure 1, below, for wells with liquids unloading emission rates greater than 250 Mcf per year.

Figure 1. Distribution of Emissions by Well Type for Emission Rates > 250 Mcf.
Based on 107 wells measured by Allen et al. (2013)

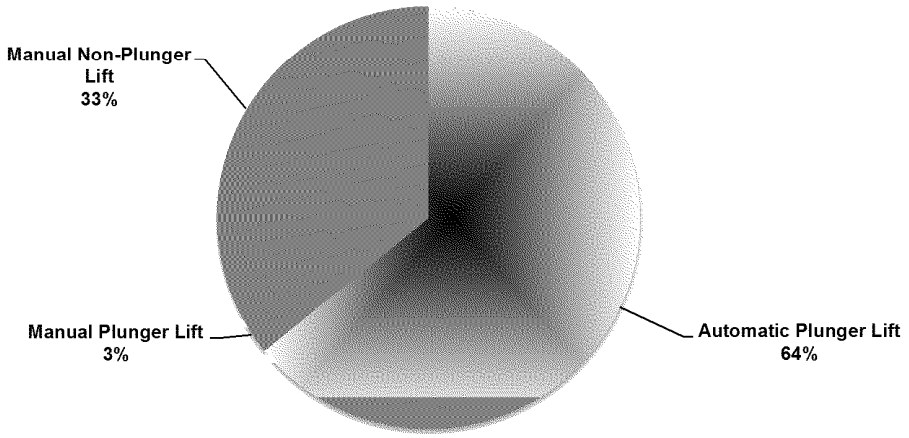


Table 1 summarizes the cost-effectiveness of deploying flares to reduce emissions from each well type (automatic plunger lift, manual plunger lift, manual non-plunger lift wells) at the 107 analyzed wells. For each, as described more fully below, the analysis assumes deployment of flaring technologies (mobile vs. stationary; and rented vs. purchased) according to certain well characteristics and provides a range of estimates for both methane and VOC cost

[4] Note, the Allen study only measured wells that vent for liquids unloading, not all wells with liquids loading activity. An API/ANGA study (Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses) based on an industry survey of over 40,000 wells reports than only 21.1% of wells equipped with plunger lifts vent. Therefore, the estimated number of wells that vented at least 250 Mcf of methane per year assumes 78.9% of plunger lift wells do not vent.

[5] For comparison, EPA's NSPS Subpart OOOO analysis determined measures associated with costs of $4,360 per ton of VOC reduction to be cost effective (for LDAR at processing plants for connectors). *See* EPA NSPS Subpart OOOO Background Technical Support Document for Proposed Standards, EPA-453/R-11-002 July 2011, pp. 3-2, 3-3 and 8-29.

effectiveness.[6]

TABLE 1. Cost Effectiveness of Flares for Liquids Unloading .
The analysis is based on 107 wells measured by Allen et al. 2013.

Annual Emissions Limit (Mcf methane)	Automatic Plunger Lift Wells				Manual Plunger Wells and Manual Non-Plunger Wells				All Wells				
	Stationary Flare				Mobile flare for wells venting less than 20 times per year and stationary flare for wells venting more than 20 times per year				Weighted Average Cost Effectiveness of Stationary Flares at Automatic Plunger Wells and a Combination of Mobile and Stationary Flares at Manual Plunger/Non-Plunger Wells				% of Total Emissions Reduced by Flaring
	CH_4 LOW [$ / ton]	CH_4 HIGH [$ / ton]	VOC LOW [$ / ton]	VOC HIGH [$ / ton]	CH_4 LOW [$ / ton]	CH_4 HIGH [$ / ton]	VOC LOW [$ / ton]	VOC HIGH [$ / ton]	CH_4 LOW [$ / ton]	CH_4 HIGH [$ / ton]	VOC LOW [$ / ton]	VOC HIGH [$ / ton]	
1600	$67	$120	$460	$810	$77	$140	$530	$930	$71	$120	$480	$850	82%
1450	$71	$130	$490	$860	$77	$140	$530	$930	$73	$130	$500	$880	83%
1300	$71	$130	$490	$860	$77	$140	$530	$930	$73	$130	$500	$880	83%
1150	$71	$130	$490	$860	$86	$150	$590	$1,000	$77	$130	$520	$920	85%
1000	$71	$130	$490	$860	$86	$150	$590	$1,000	$77	$130	$520	$920	85%
850	$71	$130	$490	$860	$86	$150	$590	$1,000	$77	$130	$520	$920	85%
700	$71	$130	$490	$860	$100	$180	$720	$1,300	$85	$150	$590	$1,000	86%
550	$81	$140	$560	$980	$150	$260	$1,000	$1,800	$110	$200	$780	$1,400	90%
400	$81	$140	$560	$980	$150	$280	$1,000	$1,900	$120	$210	$810	$1,500	91%
250	$100	$180	$700	$1,200	$170	$350	$1,200	$2,400	$140	$260	$940	$1,800	93%
AVERAGE	$76	$130	$520	$910	$110	$190	$730	$1,300	$91	$160	$620	$1,100	

NOTES:

All flares:

Emissions reductions are based on a 98% flare efficiency

% emissions reductions are based on measured emissions from all wells measured and at all emission rates (not the subset of emissions above 100 Mcf

Stationary Flare:

Low cost estimates are based on EPA annualized capital costs for completion combustion based on a 15 year equipment life and 7% interest plus annual operating cost estimates from CDPHE for pilot fuel and maintenance. See EPA NSPS Subpart OOOO RIA at 3-12 and TSD at 7-6 (April 2012).
See Colorado Department of Public Health and Environment, Cost-Benefit Analysis, Submitted per § 24-4-103(2.5), C.R.S., at 7 (2014)

High cost estimates are based on ICF data for capital costs for venting flares annualized, for consistency, based on EPA's assumptions of 15 year equipment life and 7% interest. Operating costs are also based on ICF estimates. See ICF International, "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries" at 3-22 (March 2014)

Mobile Flare (rented):

Cumulative annual costs for all reported venting events are calculated based on mobile flare rental costs ranging from $250 - $850/day and labor costs of $100/hr. The number of rental days is assumed to equal the reported number of venting events. Estimated labor time is based on min/max reported average sampled event duration. See ICF International Memo from Don Robinson, Joel Bluestein, Hemant Mallya, Tarang Mehta, and Mike Polchert, ICF International, to Peter Zalzal and Tomas Carbonell, EDF, June 13, 2014

VOC Cost Effectiveness:

Calculated based on ratios derived from EPA's NSPS Subpart OOOO. For liquids unloading the calculated VOC:methane ratio is 0.146.
See CATF, NRDC, Sierra Club "Waste Not: Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry" (January 2015)
See EPA NSPS Subpart OOOO RIA at Table 3-3 (April 2011)

Automatic Plunger Lift Wells.

Due to the greater frequency of unloading events at wells with automatic plunger lifts, a stationary flare is the most cost-effective flaring technology available to reduce emissions from such wells.

[6] The Allen study reported methane emissions from the sampled wells, but not VOC emissions. Accordingly, VOC cost effectiveness estimates in this analysis are calculated based on ratios of VOC:methane derived from EPA's NSPS Subpart OOOO (2011 RIA at Table 3-3). For liquids unloading the calculated VOC:methane ratio is 0.146. *See* CATF, NRDC, Sierra Club "Waste Not: Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry" (January 2015).

In estimating the cost effectiveness of stationary flares, this analysis assumes: (1) the "low cost" estimates are based on EPA data for annualized capital costs for completion combustion devices based on a 15 year equipment life and 7 percent interest rate, plus annual operating costs estimated for Colorado's oil and gas rules, which include cost estimates for pilot fuel and maintenance;[7] and (2) the "high cost" estimates are based on ICF International data for capital costs for completion and venting flares annualized – for consistency – based on EPA's assumptions of a 15 year equipment life and 7% interest rate, plus annual operating cost estimates from ICF International.[8]

As shown in Table 1, based on the wells in the Allen et al. dataset, the average cost effectiveness of employing a stationary flare at wells with automatic plunger lifts, across all emission thresholds assessed, ranges from $76-$130 per ton of methane reduced ($3 to $5 per ton CO_2-e, using a methane GWP of 25), and $520-$910 per ton of VOC reduced. The cost effectiveness of employing a stationary flare to reduce emissions at wells with automatic plunger lifts with emissions above 250 Mcf methane ranges from $100-$180 per ton of methane reduced, and $700-$1,200 per ton of VOC reduced. At the 250 Mcf methane threshold for automatic plunger lift wells, deploying stationary flares would reduce total measured emissions from all wells in the dataset by 60%.

Manual Plunger Lifts and Non-Plunger Wells.

For wells in the data set with manual plunger lifts and manually vented wells without plunger lifts, this analysis assumes the use of either a mobile flare or a stationary flares, based on the frequency of unloading events reported at the wells. For manually vented wells, vented methane emissions in the dataset are generally lower than the other measured wells, averaging around 100 Mcf per year for wells with manual plunger lifts and 1,000 Mcf per year for wells without plunger lifts compared with an average of 2,500 Mcf per year for wells using automatic plunger lifts. Well venting also occurs relatively infrequently at these wells, with an average of as few as 10 reported venting events per year for wells with manual plunger lifts and 30 per year for wells without plunger lifts compared with automated plunger lift wells (which reported over 2,000 events per year). This analysis assumes mobile flares would be deployed at manual plunger wells when the number of annual venting events is low—less than 20—and stationary flares would be deployed at wells when annual venting events exceed 20.

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[7] Annualized capital costs = $3,523 and annual operating costs = $3,000. *See* EPA NSPS Subpart OOOO RIA at 3-12 and TSD at 7-6 (April 2012). *See* Colorado Department of Public Health and Environment, Cost-Benefit Analysis, Submitted per § 24-4-103(2.5), C.R.S., at 7 (2014).

[8] Annualized capital costs = $5,490 and annual operating costs = $6,000. *See* ICF International, "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries" at 3-22 (March 2014).

In estimating the cost effectiveness of flares at wells with manual plunger lifts, we relied on the stationary flaring assumptions set forth above. For mobile flares deployed at wells with fewer than 20 venting events per year, we assume: (1) cumulative annual costs for all reported venting events are calculated based on mobile flare rental costs ranging from $250/day - $850/day and labor costs of $100/hour;[9] (2) the number of rental days is assumed to equal the reported number of venting events (*i.e.*, a mobile flare only serves one well at a time and one event per day); and (3) estimated labor time is based on the minimum and maximum reported average sampled event duration rounded up to the next hour (labor costs are then calculated at a rate of $100/hour).[10]

As shown in Table 1, the average cost effectiveness of employing a combination of stationary and mobile flares at wells with manual plunger lifts and at wells without plunger lifts, across all emission limits assessed, ranges from $110-$190 per ton of methane reduced and $730-$1,300 per ton of VOC reduced. The cost effectiveness at this same subset of wells with emissions above 250 Mcf ranges from $170-$350 per ton of methane reduced and $1,200-$2,400 per ton of VOC reduced. For wells with manual plunger lifts and without plunger lifts whose emissions exceed 250 Mcf per year, deploying this combination of mobile and stationary flares would reduce total measured emissions from all wells in the dataset by 33%.[11] The majority of these emission reductions are associated with manually vented wells without plunger lifts, which generally have higher liquids unloading emissions than wells equipped with manual plunger lifts. Accordingly, cost-effectiveness of achieving emission reductions at manually vented wells without plunger lifts is also greater than at wells with manual plunger lifts.

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[9] We note that purchasing mobile flares could further enhance cost-effectiveness for wells that unload more frequently.

[10] *See* ICF International Memo from Don Robinson, Joel Blu estein, Hemant Mallya, Tarang Mehta, and Mike Polchert, ICF International, to Pet er Zalzal and Tomas Carbonell, EDF, June 13, 2014.

[11] Calculated reductions are based on measured emissi ons from all wells measured and at all emission rates (not the subset of emissions above 1 00 Mcf).

To: Gunning, Paul[Gunning.Paul@epa.gov]; Cook-Shyovitz, Becky[Cook-Shyovitz.Becky@epa.gov]
Cc: Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]
From: Weitz, Melissa
Sent: Wed 4/13/2016 6:23:38 PM
Subject: RE: LGAC Air Workgroup: Call Wed., April 20 - GHG Inventory

Hello,

I'm available for the call and happy to give an overview of the GHG inventory.

Melissa

From: Gunning, Paul
Sent: Wednesday, April 13, 2016 2:21 PM
To: Cook-Shyovitz, Becky <Cook-Shyovitz.Becky@epa.gov>
Cc: Weitz, Melissa <Weitz.Melissa@epa.gov>; Waltzer, Suzanne <Waltzer.Suzanne@epa.gov>
Subject: RE: LGAC Air Workgroup: Call Wed., April 20 - GHG Inventory

No worries. We can certainly cover the inventory piece. I am hoping that Melissa, copied above, is available.

Paul

From: Cook-Shyovitz, Becky
Sent: Wednesday, April 13, 2016 12:11 PM
To: Gunning, Paul <Gunning.Paul@epa.gov>
Subject: LGAC Air Workgroup: Call Wed., April 20 - GHG Inventory

Hi Paul-

I'm working with OAQPS to have someone cover the methane proposal next week (sorry if I

reached out to the wrong office!).

Ex. 5 - Deliberative Process

Thanks again!

Becky

From: Cook-Shyovitz, Becky
Sent: Monday, April 11, 2016 1:13 PM
To: Gunning, Paul <Gunning.Paul@epa.gov>
Cc: Cozzie, David <Cozzie.David@epa.gov>; Moore, Bruce <Moore.Bruce@epa.gov>; Waltzer, Suzanne <Waltzer.Suzanne@epa.gov>
Subject: LGAC Air Workgroup: Call Wed., April 20 - Methane Regs

Hi all,

The Local Government Advisory Committee's Air, Climate & Energy workgroup will meet via conference call on Wednesday, April 20 from 1-2pm EST. The members have requested a briefing on the recent announcement that EPA will develop regulations for methane emissions from existing oil and gas sources.

Please let me know if you are able to join us next week to provide a 10-15 minute overview, plus about 5 minutes for Q&A. Thanks!

Becky Cook-Shyovitz

Intergovernmental Liaison

U.S. Environmental Protection Agency

202-564-5340

To: Zimmerle,Dan[Dan.Zimmerle@colostate.edu]
From: Weitz, Melissa
Sent: Mon 2/27/2017 9:04:35 PM
Subject: RE: Meeting this week

Hi Dan,

Wednesday should still work. What time does the ARPA-E summit wrap up?

Melissa

From: Zimmerle,Dan [mailto:Dan.Zimmerle@colostate.edu]
Sent: Sunday, February 26, 2017 11:29 PM
To: Weitz, Melissa <Weitz.Melissa@epa.gov>
Subject: Meeting this week

Melissa,

We had corresponded about meeting on Wednesday afternoon, after the close of the ARPA-E Innovation summit. Are you (et. al.) still open for that? Should we meet for a beer somewhere?

Daniel Zimmerle

+1 970-581-9945 (cell) | dan.zimmerle@colostate.edu |http://energy.colostate.edu/

Senior Research Associate

Director, Electric Power System Laboratory (EPSL)

PI, Methane Emissions Test and Evaluation Center (METEC)

Scheduling | Madie Van Doren | madison.van_doren@colostate.edu

Lab Management & Emergencies | Kate Laughery | Kate.Laughery@colostate.edu

From: Weitz, Melissa
Importance: Normal
Subject: call with Institute of Clean Air Companies
Start Date/Time: Tue 8/11/2015 8:00:00 PM
End Date/Time: Tue 8/11/2015 9:00:00 PM

Hello,

Paul forwarded the request below on to me. I spoke with Betsy and her group is interested in knowing more about monitoring for GHGRP, what we're thinking in terms of monitoring for Methane Challenge, and the GHG Inventory.

So, it'd be great if you could join and provide a brief overview that covers monitoring in your programs.

Does this work?

Thanks!
Melissa

From: Betsy Natz [mailto:bnatz@icac.com]
Sent: Tuesday, July 28, 2015 7:25 PM
To: Gunning, Paul
Subject: FW: Follow up information - Methane Webex - July 23, 2015

Hi Paul,

I hope you are doing well. I was wondering if you have any new information on timing, etc of the voluntary program for methane control?

Also, I was hoping that you might be able to give me some guidance on what EPA will be or is currently measuring with regard to methane emissions from industrial sources, eg fugitive emissions or other emission point sources? We are trying to get our emissions measurement division together on a webex to discuss and I just thought it would be helpful if I could get your input if you have a minute.

Many thanks,
Betsy

To: David Lyon[dlyon@edf.org]
From: Weitz, Melissa
Sent: Tue 8/25/2015 4:35:55 PM
Subject: RE: stripper well & condensate tank questions

Hi David,

I've added responses to you questions below. Are you still free to talk tomorrow at 4 EST? We can talk through these responses as well if you'd like.

Melissa

From: David Lyon [mailto:dlyon@edf.org]
Sent: Friday, August 07, 2015 3:22 PM
To: Weitz, Melissa
Subject: stripper well & condensate tank questions

Greetings Melissa,

I hope you are having a good summer in DC. We have had continuous 100 degree days in Austin for a few weeks and it likely will stay brutally hot for a couple months.

I have a few questions for you about the GHG Inventory Petroleum Systems stripper wells and Natural Gas Systems condensate tanks.

1) Which emission factors are applied to stripper wells in addition to the 2,345 scf/yr venting factor? Do the fugitive wellhead factors also apply to stripper wells? Why does the oil tank activity data only include production from non-stripper wells?

The Inventory applies the 2,345 scf/yr venting factor to 80% of stripper wells.

For 3 source categories, adjustments are made to exclude those 80% of stripper wells from other calculations (and therefore include 20% of stripper wells)--

Oil tanks—This estimate is based on total oil production, minus 80% of stripper well production.

Throughput is estimated based on:

Total Crude Oil Production in the Lower 48 States minus (80% of Total Stripper Well Production [see below]). This "80% of stripper well production" is taken from ICF "Estimates of Methane Emissions from the U.S. Oil Industry" Oct. 1999. The source of the value is: ARCO Laboratory, Plano, TX, personal communication. Based on assumed reservoir pressure of 25 to 50 psia.

Oil wellheads, heavy crude

Radian Table 5-2

Assumed that heavy crude wells are 7.05% of Total producing oil wells and 80% of stripper wells are vented.

(7.05% * Total producing oil wells) – (7.05% * Total stripper wells * 80%)

Oil wellheads, light crude

Radian Table 5-2

Assumed that light crude wells are 92.95% of Total producing oil wells and 80% of stripper wells are vented.

(92.95% * Total producing oil wells) – (92.95% * Total stripper wells * 80%)

For other source categories, factors apply to the total count of petroleum-producing wells

and/or total petroleum production. Stripper wells and stripper well production are included in both of those categories.

2) Can EPA share any data used to develop the condensate tank scf/bbl emission factors? I am trying to calculate hydrocarbon emissions from tank flashing in several basins (Barnett, Eagle Ford, Bakken, Fayetteville, Uintah, Marcellus, and Power River). It would be helpful if I had basin specific emission factors or parameters such as separator pressure and API gravity that I could use to develop factors. The emission estimates will be used in context of infrared camera detections, so it is most important to know total hydrocarbon emissions, but any information you have on the speciation of tank flashing emissions would also be helpful.

Development of condensate tanks factors:

This analysis used E&P Tank sample runs to determine an un-weighted emission factor for every 5°API gravity interval. This consists of ordering the sample runs by API gravity, grouping the sample runs by 5°API gravity intervals, and taking the simple average of uncontrolled emission rates from runs in each interval. The resulting emission factors for each range are shown in Exhibit 1.

Exhibit 1. Un-Weighted Flashing Methane Emission Factors by API Gravity

API Gravity From:	To:	Average (scf CH_4/bbl)
Oil		
0	19	2.10
20	24	3.18
25	29	2.67
30	34	10.15
35	39	6.80
40	44	9.06
Condensate		
45	49	6.62
50	54	45.57
55	59	106.73
60	+	101.89

To account for the production profile of hydrocarbons of varying API gravity in the United States, this analysis used the HPDI database[1]. HPDI accumulates data from thousands of properties that report oil and gas production to their relevant state commissions. The database was filtered for entries that include API oil gravity. As a result, the filtered data consists of a substantial number of reporting properties from Louisiana, Mississippi, New Mexico, Texas, and parts of the Gulf of Mexico.

The API gravity of the hydrocarbon produced in the reporting property was matched with an un-weighted emission factor from Table 1. This emission factor was multiplied by the production rate to determine unadjusted emissions from the property. In addition, if the reporting properties are classified as marginal, it is assumed that only 80% of the production degasses through a storage tank (consistent with the existing Inventory activity factor methodology). All produced oil from non-marginal wells is assumed to pass through a separator and have flashing emission in the downstream storage tank. The emissions from tanks with hydrocarbons below 45° API gravity (oil) and above or equal to 45° API gravity were totaled separately. To determine an emission factor for oil and condensate tanks, the emissions from the respective API gravity range was divided by the total production of oil and condensate from non-marginal wells as shown in Exhibit 2.

Exhibit 2. Equation for Weighted Flashing Methane Emission Factor

$$EF_i = \frac{\sum_y \left(ef_y \times p_y\right)}{\sum_y q_y}$$

Where,

i = **index representing oil (<45) or condensate (≥ 45);**

y = **index representing reporting property;**

EF_i = **weighted flashing emission factor (scf/bbl);**

ef_y = **non-weighted flashing emission factor associated with the gravity range for reporting property y (scf/bbl);**

p_y = **assumed tank throughput from reporting property y;**

q_y = **non-marginal well production from property *y* (bbl).**

The calculated emission factors using Exhibit 2 are 7.06 and 71.02 standard cubic feet per barrel (scf/bbl) for oil and condensate tanks, respectively.

The emission factors calculated using Exhibit 2 account for flashing emissions from condensate and oil tanks. However, in some cases produced gas from the separator will bypass the liquid dump valve and vent through the storage tank. Anecdotal evidence from Natural Gas STAR Partners suggests the existence of this phenomenon, in addition to two measurement studies, one conducted by the Texas Environmental Research Consortium (TERC)[2] and another by the Texas Commission on Environmental Quality (TCEQ)[3] that were analyzed to make quantifiable adjustments to the tank emission factors.

The studies measured tank emissions from a combined 69 crude oil and condensate storage tank batteries. The TCEQ study also compared its measured results to those obtained from other quantification methods – such as E&P Tank. The TERC study did not provide E&P Tank simulation results, so this study performed a calculation to make a comparison. It used the Vasquez-Beggs Equation on the data provided for the 36 batteries in TCEQ and determined the average ratio of E&P Tank results to Vasquez-Beggs results for the gas-to-oil ratio (GOR) of the flash emissions. It then performed the same Vasquez-Beggs correlation to 32 of the 33 tank batteries in TERC and used the ratio to back-calculate an estimate of E&P Tank results. This analysis excluded one of the 33 data points because the TERC study states that a well was completed with the gas routed through the tank battery during measurement.

The average ratio of measured emissions to the E&P Tank simulated (or estimated) emissions was calculated separately for crude oil and condensate tanks. In some tank batteries, the simulation of flashing emissions corresponded reasonably well (within 100%) with the measured emissions. However, in 30 of the 68 accepted cases, or 44% of the cases, the measured emissions were much different; typically higher. The resulting ratios of measured emissions to E&P Tank estimated flashing emissions was 2.17 for crude oil and 4.26 for condensate. The remaining regions were not altered due to lack of representative data.

HPDI, TERC, and TCEQ provide data for the Mid-Central and Southwest NEMS regions. As a result, the condensate tank emission factors for these regions are adjusted for the

distribution of condensate production and scaled up by 4.26 for dump valve blow through emissions.

In addition, the analysis sought to scale up the emission factor for blow-through for oil tanks. It was determined that the production from the 9 counties in which the tanks in the TERC and TCEQ studies are found, represent 4 percent of the production in the United States. Consequently, 4 percent of the emission factor for oil tanks was scaled up by 2.17 while the remaining 96 percent the emission factor remained unchanged due to lack of representative data.

Vapor recovery units (VRUs) are common control methods for emissions from condensate tanks. To account for the reductions as a result of VRU's, 80% of emissions are assumed to be captured by the control technologies, following previous inventory methodologies.

The emission factors used for oil and condensate tanks are as shown in Exhibit 3.

Exhibit 3. Methane Emission Factors for Condensate Tanks with or without Control Devices.

Region	Emission Factor		
	Condensate Tanks without Control Devices	Condensate Tanks with Control Devices	Oil Tanks[1]
North East	21.87	4.37	7.39
Mid-Central	302.75	60.55	
Rocky Mountain	21.87	4.37	
South West	302.75	60.55	
West Coast	21.87	4.37	
Gulf Coast	21.87	4.37	

[1]Emission estimates, activity factors and emission factors for Petroleum Systems are not broken up by NEMS region.

Thanks,

David

David Lyon

Scientist

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(512) 691-3414
dlyon@edf.org

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[1] HPDI Production and Permit Data, October 2009.

[2] TERC. *VOC Emissions from Oil and Condensate Storage Tanks*. October 31, 2006.

[3] TCEQ. *Upstream Oil and Gas Storage Tank Project Flash Emissions Model Evaluation*. July 16, 2009.

To: DeLuca, Isabel[DeLuca.Isabel@epa.gov]; Gunning, Paul[Gunning.Paul@epa.gov]; Birnbaum, Rona[Birnbaum.Rona@epa.gov]; Franklin, Pamela[Franklin.Pamela@epa.gov]; Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]
Cc: Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Birgfeld, Erin[Birgfeld.Erin@epa.gov]; Wirth, Tom[Wirth.Tom@epa.gov]
From: Weitz, Melissa
Sent: Wed 11/20/2013 10:18:54 PM
Subject: RE: ACTION: AP science writer seeks EPA comments on upcoming embargoed PNAS methane study

Haven't heard of it. I'll also check with Tom Wirth since it mentions agriculture emissions.

From: DeLuca, Isabel
Sent: Wednesday, November 20, 2013 4:39 PM
To: Gunning, Paul; Birnbaum, Rona; Franklin, Pamela; Kocchi, Suzanne; Irving, Bill
Cc: Waltzer, Suzanne; DeFigueiredo, Mark; Weitz, Melissa; Birgfeld, Erin
Subject: FW: ACTION: AP science writer seeks EPA comments on upcoming embargoed PNAS methane study
Importance: High

Heads up—we have an inquiry about an upcoming PNAS article that says EPA is underestimating US methane emissions. Have any of you heard of this yet? If we get a copy in advance of Monday's release, we'll share it.

From: Dennis, Allison
Sent: Wednesday, November 20, 2013 4:33 PM
To: Valentine, Julia; Davis, Alison; Drinkard, Andrea
Cc: Birgfeld, Erin; DeLuca, Isabel
Subject: RE: ACTION: AP science writer seeks EPA comments on upcoming embargoed PNAS methane study

- Dave and John

+ Erin and Isabel

Julia- Will the reporter share the PR and/or study?

From: Valentine, Julia
Sent: Wednesday, November 20, 2013 4:29 PM
To: Davis, Alison; Drinkard, Andrea; Dennis, Allison
Cc: Millett, John; Cohen, David
Subject: ACTION: AP science writer seeks EPA comments on upcoming embargoed PNAS methane study

This request came in to OPS. If we haven't seen it, guessing we'll say that we will review or something similar?

Thanks.

Seth Bornstein

AP

There's a study in the journal Proceedings of the National Academy of Sciences that's embargoed till 3 p.m. EST Monday (please honor). It basically says, that EPA calculations on total US methane emissions may be underestimating the true values by 50 percent, especially because of agriculture and refineries. The study found large discrepancies with government estimates in some regions of the United States, particularly the south-central US, where total methane emissions were 2.7 times greater than those reported in most inventories.

To: Staudt, Amanda[AStaudt@nas.edu]; Gunning, Paul[Gunning.Paul@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]
Cc: Thomas, Katherine C[KCThomas@nas.edu]
From: Weitz, Melissa
Sent: Tue 12/15/2015 4:14:26 PM
Subject: RE: Methane emissions study - NASA support

Hello Amanda,

We're pleased to let you know that EPA will be able to contribute $200K to the methane emissions study.

We are working on moving the funding package forward and expect that it will be ready in early 2016 (hopefully first few weeks of January).

Best,

Melissa

Melissa Weitz

Climate Change Division

U.S. Environmental Protection Agency

(202) 343-9897

Weitz.Melissa@epa.gov

From: Staudt, Amanda [mailto:AStaudt@nas.edu]
Sent: Tuesday, December 15, 2015 10:49 AM
To: Gunning, Paul <Gunning.Paul@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>; Irving, Bill <Irving.Bill@epa.gov>
Cc: Thomas, Katherine C <KCThomas@nas.edu>

Subject: Methane emissions study - NASA support

Dear Paul, Melissa, and Bill,

Good news! NASA has agreed to contribute $120k to the methane emissions study. This puts us pretty close to reaching our target. I'm reaching out to USDA and DOE one more time to see if they can contribute something as well, since we're just a little bit short at this point.

Let us know if you need anything on your end to move the proposal process along for EPA. It would be great if we can get things moving so we can start working on the project in early 2016.

Thanks!

Amanda

Amanda Staudt, Ph.D., Director

Board on Atmospheric Sciences and Climate

Polar Research Board

The National Academies of Sciences, Engineering, and Medicine

(202) 334-1245

http://dels.nas.edu/basc

http://dels.nas.edu/prb

To: Gunning, Paul[Gunning.Paul@epa.gov]; Friedman, Kristina[Friedman.Kristina@epa.gov]
Cc: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]
From: Weitz, Melissa
Sent: Mon 12/14/2015 10:10:24 PM
Subject: Background and one pager on Aliso Canyon Storage Well CH4 Leak
Aliso Canyon Storage CH4 Leak.docx

Please see attached one pager, and the link below to an LA Times article which gives a good overview of the Aliso Canyon Storage well leak issue.

http://www.latimes.com/local/california/la-me-1121-gas-leak-20151121-story.html

To: Karin C. Ritter[Ritterk@api.org]
From: Weitz, Melissa
Sent: Fri 8/14/2015 9:46:35 PM
Subject: RE: IPCC Contacts?

Thanks Karin! Have a nice weekend!

From: Karin C. Ritter [mailto:Ritterk@api.org]
Sent: Tuesday, August 11, 2015 5:27 PM
To: Weitz, Melissa
Subject: RE: IPCC Contacts?

Good to hear you on the phone earlier today Melissa.

I've attached an "example" speaker invite letter (using Lisa's name) to give you some background on the upcoming IPIECA workshop on methane emissions in the oil and gas sector. We are still working on the details of the agenda and could share that at a later time.

From: Karin C. Ritter
Sent: Friday, August 07, 2015 11:04 AM
To: 'Weitz, Melissa'
Subject: RE: IPCC Contacts?

Melissa,

Very timely….thank you.

I'm here all day with no conference calls scheduled.

Karin

From: Weitz, Melissa [mailto:Weitz.Melissa@epa.gov]
Sent: Friday, August 07, 2015 10:22 AM
To: Karin C. Ritter
Subject: RE: IPCC Contacts?

Hi Karin,

Sorry for the delay-

Lisa's contact info is Ex. 6 - Personal Privacy She may have some additional suggestions for potential speakers.

John Watterson is with AEA, a consulting firm that works with UK on its GHG inventory.
Ex. 6 - Personal Privacy

I'll give you a call later today to follow up on this and to check in on some other things.

Thanks,

Melissa

From: Karin C. Ritter [mailto:Ritterk@api.org]
Sent: Thursday, August 06, 2015 4:07 PM
To: Weitz, Melissa
Subject: RE: IPCC Contacts?

Melissa,

Thought maybe you had missed seeing this email?

Thank you

Karin

From: Karin C. Ritter
Sent: Friday, July 31, 2015 3:17 PM
To: Melissa Weitz

Subject: IPCC Contacts?

Hi Melissa

Thank you for your call back!

You mentioned Lisa. That would be great. Can you remind me who she's with and contact information for her?

You also mentioned John Waterson in the UK. Again same question. Who is he with and contact information?

Have a great weekend,

Karin

Karin Ritter

Regulatory and Scientific Affairs

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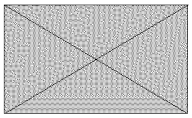

To: Marchese,Anthony[Anthony.Marchese@colostate.edu]
From: Weitz, Melissa
Sent: Fri 5/9/2014 8:50:38 PM
Subject: RE: Question on GHG Inventory

Hi Anthony,

In the Inventory, natural gas production and gathering and boosting are grouped together in the "production" category of the Inventory. Gathering and boosting sources included in the production category of the Inventory include small reciprocating compressors, large reciprocating compressors, large reciprocating stations, pipeline leaks, pipeline blowdowns, compressor starts, compressor blowdowns, compressor exhaust, dehydrators, and kimray pumps.

Let me know if you have other questions.

Melissa

Melissa Weitz

Climate Change Division

U.S. Environmental Protection Agency

(202) 343-9897

Weitz.Melissa@epa.gov

From: Marchese,Anthony [mailto:Anthony.Marchese@colostate.edu]
Sent: Tuesday, May 06, 2014 5:49 PM
To: DeFigueiredo, Mark; Zimmerle,Dan
Cc: Weitz, Melissa
Subject: RE: Question on GHG Inventory

Melissa,

CSU is the lead organization on a study organized by the Environmental Defense Fund to quantify total methane emissions from the midstream (i.e. gathering and processing) sector of the U.S. natural gas supply chain. This is one of several studies organized by EDF to try to get a better estimate on the entire supply chain. For the purposes of the EDF study, we have defined the midstream sector as everything downstream of the well site and upstream of the transmission sector (although in some cases midstream interfaces directly with distribution).

We are entering the stage of our study where we are beginning to compare our emissions measurements with those that are in the EPA greenhouse gas inventory.

In our study we have measured the facility level emissions from approximately 140 gathering facilities and processing plants from among 5 different companies and in 13 different U.S. states. Based on my understanding of the EPA greenhouse gas inventory, we will be able to compare our measurements from the processing plants directly against the inventory tabulated in Tables 3-44 (page 3-63) and A-128 (pageA-185) from the new 2012 inventory. It is unclear, however, if the "gathering facilities" measured in our study are included in the EPA inventory at all. These facilities are typically compressor stations (many of which include dehydration, some include amine treatment) that gather natural gas from a collection of wells (10 to 100) with a typical throughput of 0.5 to 15 MMsfcd. A typical station might have 4 large reciprocating engines/compressors. These facilities can be fairly large and they are typically unmanned.

A perusal of the EPA Inventory shows that the Natural Gas Production Stage (e.g. Table A-125) lists Gathering Compressors. However, my guess is that these compressors are not the compressors that are located on our "gathering facilities". If my premise is correct, are the gathering facilities are omitted from the inventory altogether?

Thank you for your time. I'd be happy to chat with you about this on the phone if that is helpful.

Best Regards,

Anthony

Anthony J. Marchese, Ph.D.

Director, Engines and Energy Conversion Laboratory

Associate Professor, Department of Mechanical Engineering

A103H Engineering

Colorado State University

Fort Collins, CO 80523-1374

Campus: (970) 491-2328

Lab: (970) 491-4786

Cell: (267) 528-7954

marchese@colostate.edu

http://www.engr.colostate.edu/~marchese/

From: DeFigueiredo, Mark [mailto:DeFigueiredo.Mark@epa.gov]
Sent: Tuesday, May 06, 2014 3:09 PM
To: Zimmerle,Dan; Marchese,Anthony
Cc: Weitz, Melissa
Subject: RE: Question on GHG Inventory

Hi Dan –

My colleague Melissa Weitz leads our GHG Inventory work on oil and gas. Feel free to email us your questions.

Best wishes,

Mark

--

Mark de Figueiredo, J.D., Ph.D.

Climate Change Division

U.S. Environmental Protection Agency

(202) 343-9928

defigueiredo.mark@epa.gov

From: Zimmerle,Dan [mailto:Dan.Zimmerle@colostate.edu]
Sent: Tuesday, May 06, 2014 4:01 PM
To: DeFigueiredo, Mark; Marchese,Anthony
Subject: Question on GHG Inventory

Mark,

We are working on the analysis for our midstream study, and have a few questions about the handling of midstream in the GHG inventory. Is that an area where your team can answer questions, or can you point me at a person who can answer? Note this is on GHGI, not SubW.

Dan.

Daniel Zimmerle

970-581-9945 (cell)

dan.zimmerle@colostate.edu

430 N College Avenue

Fort Collins, CO 80524

To schedule appointments, contact my assistant:

Jes Mallory

Jessica.Mallory@colostate.edu

Assistant Research Professor

Director, Electric Power System Laboratory

Energy Institute @Colorado State University

http://eecl.colostate.edu/research/renewable.php

Scientific Director

Center for Research and Education in Wind

Colorado Renewable Energy Collaboratory

http://crew.colorado.edu/

Aliso Canyon Natural Gas Storage Leak

- On October 23, 2015, Southern California Gas informed the State of California of a natural gas leak at its Aliso Canyon natural gas storage facility. Aliso Canyon is the largest natural gas storage site in the Western United States.

- The leaking gas is coming from a pipe enclosed in a seven-inch well casing. The well is 8,750 feet deep and the leak is about 480 to 500 feet underground. The well is releasing 50 tonnes of methane per hour.

    - CARB calculates that the Aliso Canyon well is responsible for over a quarter of California's daily methane emissions.
    - The well is estimated to have emitted around 1.5 million metric tons CO2e of methane since the leak started.

- Southern California Gas has maintained that the gas leak is not a risk to the public. However, residents have complained of headaches, nose bleeds and other issues. At least 1,000 households are requesting relocation from the area.

- Officials estimate that it could take up to four months to plug the well. The company has tried at least six times to kill the leak but so far has been unsuccessful.

To: Gunning, Paul[Gunning.Paul@epa.gov]
Cc: Irving, Bill[Irving.Bill@epa.gov]; Kocchi, Suzanne[Kocchi.Suzanne@epa.gov]; Alsalam, Jameel[Alsalam.Jameel@epa.gov]; Hight, Cate[Hight.Cate@epa.gov]; Fawcett, Allen[Fawcett.Allen@epa.gov]
From: Weitz, Melissa
Sent: Fri 12/20/2013 8:18:53 PM
Subject: FW: V2 incorporating all suggestions
preliminary upstream results 122013 v2.docx

Hello Paul,

A group of us provided inventory numbers and projections to OAQPS to do a preliminary look at upstream emissions impacts of a power sector scenario that induces an increase in production of natural gas and a decrease in production of coal.

Ex. 5 - Deliberative Process

Do you have concerns with Alex sending this preliminary assessment on to Peter? Would you like additional background?

Thanks,

Melissa

From: Macpherson, Alex
Sent: Friday, December 20, 2013 2:40 PM
To: Weitz, Melissa; Chappell, Linda; Alsalam, Jameel; Sims, Ryan; Hight, Cate
Subject: V2 incorporating all suggestions

All,

Here is a revised version with all changes, including the below which revised Ryan's statement from the previous msg.

Are we good to go? If yes, I will reach out to Ravi first thing Monday am.

Alex

Ex. 5 - Deliberative Process

To: Gunning, Paul[Gunning.Paul@epa.gov]
From: Weitz, Melissa
Sent: Tue 12/2/2014 2:43:19 PM
Subject: RE: Information for next week's meeting on methane emissions

Yes

From: Gunning, Paul
Sent: Tuesday, December 02, 2014 9:43 AM
To: Weitz, Melissa
Subject: RE: Information for next week's meeting on methane emissions

Yes, lets grab a cab. Are you ready now?

From: Weitz, Melissa
Sent: Tuesday, December 02, 2014 9:38 AM
To: Gunning, Paul
Subject: RE: Information for next week's meeting on methane emissions

Are you heading over from here? What time are you planning to leave?

From: Gunning, Paul
Sent: Monday, December 01, 2014 1:28 PM
To: Weitz, Melissa
Subject: RE: Information for next week's meeting on methane emissions

Yes, I just had them add you to the meeting. Glad you can go!!

From: Weitz, Melissa
Sent: Monday, December 01, 2014 10:37 AM
To: Gunning, Paul
Cc: Irving, Bill

Subject: RE: Information for next week's meeting on methane emissions

Thanks Paul. I'm very interested in attending if I can be added. Thanks!

From: Gunning, Paul
Sent: Monday, December 01, 2014 9:16 AM
To: Weitz, Melissa
Cc: Irving, Bill
Subject: RE: Information for next week's meeting on methane emissions

Melissa – I hope you had a great holiday. If you are available, it would be great if you could attend this meeting with me. Let me know and I will touch base with the organizers to see if I can get you added.

Thanks

From: Thomas, Katherine C [mailto:KCThomas@nas.edu]
Sent: Wednesday, November 26, 2014 4:53 PM
To: Thomas, Katherine C
Subject: Information for next week's meeting on methane emissions

Dear meeting participants,

Thank you for agreeing to participate at the upcoming NRC planning meeting on *Estimating, Monitoring, and Mitigating Anthropogenic Methane Emissions* to be held next **Tuesday, Dec. 2, 10am-3pm at the Keck Center**. Please see attached updated agenda and participant list.

As a reminder, there are two main goals for this meeting:

1. Facilitate engagement of relevant agencies and experts in a discussion of the topic

2. Develop a potential NRC study or workshop, brainstorm list of questions to be answered during activity, and identify potential sources of financial support

There is a session at 11:20am on agency needs. Please be prepared to discuss the following questions informally as part of the discussion (no need for PowerPoint slides):

•□□□□□□□ What are key gaps in knowledge and data?

•□□□□□□□ What are priority needs and target audiences?

•□□□□□□□ What questions would an NRC study or workshop address that could add value to current and future efforts?

•□□□□□□□ What is the appropriate breadth for the topic?

Please let me know if you have any questions. We look forward to robust discussions at our meeting.

Have a happy Thanksgiving!

Best,

Katie

Katie Thomas
Program Officer

Board on Atmospheric Sciences and Climate
The National Academies
500 Fifth Street NW
Washington, DC 20001
202-334-3860

kcthomas@nas.edu

Cc: DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; Alsalam, Jameel[Alsalam.Jameel@epa.gov]; Franklin, Pamela[Franklin.Pamela@epa.gov]; Irving, Bill[Irving.Bill@epa.gov]; Banks, Julius[Banks.Julius@epa.gov]; Fawcett, Allen[Fawcett.Allen@epa.gov]
To: Gunning, Paul[Gunning.Paul@epa.gov]
From: Weitz, Melissa
Sent: Wed 1/31/2018 7:38:25 PM
Subject: Re: Oil and Gas Rule Makings

We pulled together the draft bullets below. Please let us know if this is the right level of detail, etc. Thanks!

OAP Support for OOOOa Reconsideration

- OAP is providing staff and contractor support for the OOOOa reconsideration packages
- Providing methane and activity data for relevant oil and gas sources (oil and gas sources, U.S. totals, global totals)
    - GHG Inventory
    - GHGRP
- Technical analysis related to key questions on emissions and technologies
    - Emissions from low-producing wells
    - Population of low-producing wells
    - Researching gas composition data
- Economic analysis, e.g. for RIA
- Input related to methane and climate science

From: Gunning, Paul
Sent: Wednesday, January 31, 2018 1:47 PM
To: Weitz, Melissa
Cc: DeFigueiredo, Mark; Waltzer, Suzanne; Alsalam, Jameel; Franklin, Pamela; Irving, Bill; Banks, Julius; Fawcett, Allen
Subject: RE: Oil and Gas Rule Makings

Thanks Melissa. COB tomorrow is actually fine.

From: Weitz, Melissa

Sent: Wednesday, January 31, 2018 12:34 PM
To: Gunning, Paul <Gunning.Paul@epa.gov>
Cc: DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>; Waltzer, Suzanne <Waltzer.Suzanne@epa.gov>; Alsalam, Jameel <Alsalam.Jameel@epa.gov>; Franklin, Pamela <Franklin.Pamela@epa.gov>; Irving, Bill <Irving.Bill@epa.gov>; Banks, Julius <Banks.Julius@epa.gov>; Fawcett, Allen <Fawcett.Allen@epa.gov>
Subject: Re: Oil and Gas Rule Makings

Sure-we'll have something for you by the end of the day.

From: Gunning, Paul
Sent: Wednesday, January 31, 2018 12:23 PM
To: Weitz, Melissa
Cc: DeFigueiredo, Mark; Waltzer, Suzanne; Alsalam, Jameel; Franklin, Pamela; Irving, Bill; Banks, Julius; Fawcett, Allen
Subject: Oil and Gas Rule Makings

Melissa - Can you please work with the team to pull together some short bullets that outline how we are supporting the oil and gas rule makings that I can share with Sarah. Not a workplan, but just identifying the specific support/technical roles we are playing. I believe she just wants to make sure that Bill is aware of what we are doing as this is one of his priorities Something by the end of the day would be great if possible.

Thanks!!

Paul

To: McKittrick, Alexis[McKittrick.Alexis@epa.gov]
From: Weitz, Melissa
Sent: Wed 12/2/2015 12:22:29 AM
Subject: comparison with new data
Comparison with new data 12.1.docx

;
I am now realizing that I never sent you the NSPS2 comparison with new data document to check the GHGRP numbers. Awesome!

Ex. 5 - Deliberative Process

Thanks! Let me know if this makes sense and when you/Natalie may be able to take a look.

To: Gunning, Paul[Gunning.Paul@epa.gov]
Cc: Irving, Bill[Irving.Bill@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]
From: Weitz, Melissa
Sent: Wed 11/26/2014 8:07:13 PM
Subject: EDF/UT Methane Project Phase 2 Briefing next Wednesday

;;;;
;;;;
UT Austin/EDF has offered to give us an embargoed pre-release briefing of results of phase II of the production CH4 study (focus on emissions from pneumatic devices and liquids unloading).

They are planning to do a shorter policy-oriented briefing and a longer technical-oriented briefing. I am working with Kristina F. to get the briefings scheduled. They will likely take place next Wednesday (December 3) afternoon.

The study will be published in early- to mid-December.

Melissa

From: Stanzione, Maria R [mailto:maria.stanzione@mail.utexas.edu]
Sent: Friday, November 21, 2014 4:25 PM
To: Irving, Bill
Cc: Adam Pacsi; Bushn, Rachael
Subject: UT Methane Project Phase 2 Briefing

Hello Bill,

I left a voicemail message for you earlier today. You may recall that we worked together in September 2013 to arrange for Dr. David Allen to give embargoed pre-release briefings to the EPA on the results of the Methane Emissions in Natural Gas Production Study. We are in the process of planning the release of the findings of Phase 2 of that study, focusing on emissions from pneumatics devices and unloadings.

I am writing to see if the EPA would like for Dr. Allen to give similar embargoed briefings on the findings from Phase 2. We are anticipating the findings being published in the journal of Environmental Science and Technology in early to mid-December.

Dr. Allen will be in Washington DC on Dec. 3rd and 4th, and would be available to give embargoed pre-release briefings on either of those days. He could also give briefings after the journal article is released.

Last year he actually gave 2 pre-release embargoed briefings, one that was longer and oriented towards a more technical audience and one that was shorter and aimed towards a more policy oriented audience.

Dr. Allen would be able to give embargoed briefings to either or both of these groups again, if desired.

If you would like to schedule something on Dec. 3rd or 4th, please let me know. If there are other dates, that would be better, we may be able to accommodate them as well.

Please note that I have included 2 UT staff, Adam and Rachael, in this email. Please be sure to copy them in any responses, as they are assisting in setting Dr. Allen's schedule. (Contacts are: maria.stanzione@austin.utexas.edu, adam.pacsi@gmail.com, and rbushn@mail.utexas.edu.)

We look forward to hearing from you.

Thank you,

Maria

Maria Stanzione, M.Ed.
Project Manager
Center for Energy and Environmental Resources
University of Texas at Austin
(512) 232-5040

maria.stanzione@austin.utexas.edu

To: Frantz, Chris[Frantz.Chris@epa.gov]; Macpherson, Alex[Macpherson.Alex@epa.gov]; DeFigueiredo, Mark[DeFigueiredo.Mark@epa.gov]; Waltzer, Suzanne[Waltzer.Suzanne@epa.gov]; Thoma, Eben[Thoma.Eben@epa.gov]; Snyder, Jennifer[Snyder.Jennifer@epa.gov]
From: Weitz, Melissa
Sent: Fri 2/13/2015 10:08:29 PM
Subject: memos for public review draft
Revision to Refineries Emissions Estimate clean 2015-02-11.docx
PR refineries tracked changes 2.11.docx
Revision to Offshore Platforms Emissions Estimate clean 2015-02-11.docx
PR offshore tracked changes 2.11.docx
HF Gas well completion and workover update memo clean 2.11.docx
PR completions and workovers tracked changes 2.11.docx
Revision to Data Source for Well Counts clean 2015-02-11.docx
PR well counts tracked changes 2.11.docx

;;;
Attached are the revised memos on updates to the GHG Inventory that will be posted to our website along with the public review draft.

Generally, there haven't been major changes since the memos were posted for expert review other than updating them to describe how the update was implemented in the public review draft, but if you are interested, please see attached.

For each memo, I've attached both the clean version and a version that shows changes from the expert review version.

Soon I'll send around memos on pneumatics and liquids unloading which will be new and exciting.

The public review draft will go out end of next week, early the week of the 23rd. Comments by COB Wednesday Feb 18th would be great.

Thanks!

Melissa

Melissa Weitz

Climate Change Division

U.S. Environmental Protection Agency

(202) 343-9897

Weitz.Melissa@epa.gov